BC Hydro
Power smart

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October 3, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

**RE: Project No. 1598922**
**British Columbia Utilities Commission (BCUC or Commission)**
**British Columbia Hydro and Power Authority (BC Hydro)**
**Site C Inquiry – Round 2 Information Responses**

The Commission's Preliminary Report set out a number of questions for BC Hydro, specifying a due date of October 4, 2017. The Commission asked that we endeavour to provide answers as they become available.

As noted in our previous IR submission, our approach has been to number all of the requests in the Preliminary Report starting with BCUC IR 2.1.0 (representing the first question in the second round of questions the Commission has posed to BC Hydro). The number of responses enclosed with this letter are non-sequential, as we are providing responses as soon as they become available.

The response to BCUC IR 2.16.0 is partially redacted to protect commercially sensitive load and business information of individual customers. An unredacted version has been filed with the Commission on a confidential basis under separate cover. The information redacted falls within Category C in the Commission's existing order addressing confidentiality (refer to Filings A-11 and F1-2), which the Commission has ordered to be accessible to the Commission itself.

In the event the Commission requires clarification of any of these responses, we would be pleased to do that. We will forward the next batch of responses as soon as they are available.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

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Enclosure

**16.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 55-56**

2.16.0 The Panel requests that BC Hydro respond to the following questions related to its industrial demand forecast:

- With regard to BC Hydro's forecast for LNG load, please provide a more detailed justification for why it considers it appropriate to continue to include each of the three LNG projects (i.e. FortisBC Tilbury LNG Phase 2, Woodfibre LNG and LNG Canada) in its load forecast.
- Please explain how the completion risk and, separately, the timing risk are factored into BC Hydro's current load forecast in relation to each of the following. If there are differences between the factoring of completion and timing risk for the three LNG projects as compared to other industrial projects/customers, please identify, explain and justify the differences:
    - **a.** FortisBC Tilbury LNG Phase 2;
    - **b.** Woodfibre LNG;
    - **c.** LNG Canada; and
    - **d.** Other industrial projects and customers.
- Based on Table 11 of BC Hydro's submission (and provided in this report above) which shows the incremental industrial load impacts of known developments and the more detailed discussion in Appendix J, for each specific development identified in Appendix J in each of the large industrial (transmission) sectors, please quantitatively and qualitatively provide the probability of each identified increase (or decrease) in load materializing. For the developments which are expected to result in increases to the industrial load, please explain in detail the risks which may prevent the identified loads from materializing and assign a risk level to each identified load.
- Please confirm, otherwise explain, that the Fortis Tilbury and LNG Canada loads and demands are the total expected electricity loads and demands from these two projects and not probability weighted amounts.
- Please provide separate unweighted load and demand schedules to F2036 for each of the FortisBC Tilbury LNG Phase 2 project, the Woodfibre LNG project and the LNG Canada project. Please provide schedules for both what was included in the Current Load Forecast and what is included in the revised outlook. Please use the same format as used in Tables J-8 and J-9.
- If there were other LNG projects (weighted or unweighted) included in the Current load and demand forecasts, please identify those projects and provide their respective Current and revised load and demand schedules. Please comment on any differences.
- In Tables J-8 and J-9, BC Hydro shows Tilbury and LNG Canada loads. In Table

K-2, BC Hydro shows total LNG load. Please explain where the remaining load is coming from. Is it all from the Woodfibre LNG project? Please elaborate.

The Panel also invites further submissions from other parties on the updates made to the LNG forecasts and others identified changes in industrial load as summarized in Table 21, including any further data that could assist the Panel in concluding on the implications of developments since the Current Load Forecast was prepared that will impact industrial demand in the short, medium and longer terms.

**RESPONSE:**

**BC Hydro's response to this information request is organized as follows: (1) LNG Load-related; (2) Other Large Industrial (Transmission) Load; and (3) Assessment of completion and timing risk for LNG and other industrial projects.**

**(1) LNG Load-Related**

**BC Hydro adopted a binary approach to including the three LNG projects requesting service from BC Hydro in its load forecast. This approach differs from the probability-based approach we typically use in developing our industrial load forecast. The distinction between the two approaches and the rationale for how the LNG project loads were treated is addressed in section (3) of this response.**

**It is appropriate to continue to include LNG Canada, Woodfibre LNG and FortisBC Tilbury Phase 2 in the Current Load Forecast for both macroeconomic reasons, which equally apply to all three projects, and project-specific reasons. A summary of relevant macroeconomic and project-specific information is provided below. This section also provides responses to the LNG project-specific information requested above; a summary of other relevant factors in considering future B.C. LNG and associated upstream natural gas production.**

**<u>Macroeconomic Justification for Including LNG Projects</u>**

**As noted in Appendix J to our August 30 Filing, we conducted a review of reputable third party sources (Wood Mackenzie, IHS, National Energy Board, Bloomberg). This review indicates the current LNG market evaluation is similar to the assessment BC Hydro used to develop the Current Load Forecast. As stated in Appendix J, key conclusions include:**

- **LNG development in B.C., as well as worldwide, still faces significant uncertainty regarding timing and scope.**
- **The LNG supply glut is anticipated to continue for the next five to ten years, but demand is expected to exceed supply over the next decade, creating an opportunity window for LNG projects in that time frame.**

- **Competition with the U.S. LNG and other jurisdictions continues. However, B.C.'s competitive advantages remain unchanged from the Current Load Forecast. They include proximity to Asian markets, low cost upstream gas (Montney basin) and the approval of export licenses for most proposed LNG facilities.**

**There are valid questions as to whether B.C. LNG has missed the window of opportunity, particularly in light of the recent cancellation of the Pacific Northwest LNG and the more recent announcement that Aurora LNG proponents have decided not to advance their project. BC Hydro provides the following information, which reflects the range of current market expert perspectives with respect to the global LNG market and future potential for B.C. LNG projects. The various market perspectives range from: (1) Unchanged relative to the Current Load Forecast; (2) more pessimistic of current global oversupply and indicating delays in B.C. LNG commercial in-service dates; and (3) more optimistic in terms of indicating higher than expected global LNG growth and earlier supply/demand balance and associated prospects for B.C. LNG projects. Note that some information is commercially proprietary and has therefore been redacted.**

- **"Despite near-term headwinds, the prospects for long-term growth for LNG look positive, to serve its traditional markets, to expand into new destination countries and to develop into new applications and end-uses." (Deloitte Center for Energy Solutions. Navigating the new world of LNG. Trends, signposts, and opportunities. January 2017 https://www2.deloitte.com/content/dam/Deloitte/global/Documents/Energy-and-Resources/gx-deloitte-er-navigating-new-world-of-lng.pdf.**

- **"The share of LNG in global gas trade will grow from 10 per cent to 16 per cent mainly driven by increased distances between sellers and buyers. The LNG market will be oversupplied until 2020-2025, but additional investments are required longer term to meet demand. The current long LNG market is changing buyer behaviours and competitive dynamics and is stimulating new ways of using LNG. By 2030, between 175 and 210 bcm of new supply beyond that which is already under construction is needed to meet demand." (McKinsey Energy Insights. Global gas supply and demand perspective to 2030. July 2017). https://www.mckinseyenergyinsights.com/services/market-intelligence/reports/global-gas-and-lng-outlook.**

- **Mark Oberstoetter, Research Director at Wood Mackenzie interview on Bloomberg TV http://bloombergtv.ca/2017-07-26/news/woodmac-petronas-retreat-not-the-dealth-knell-for-canadian-lng/. Relevant comments include:**

    - **"Project-specific costs & environmental challenges killed the Pacific NorthWest LNG project."**

- **"Woodfibre and LNG Canada do not have same cost and environmental challenges that the Pacific Northwest LNG project had."**
- **"Woodfibre LNG is likely the first to come to market and is a strong proponent with size controllable on the cost side."**
- **"A lot of things going for the Kitimat locations. Less issues on the environmental sensitivities; on existing industrial sites."**
- **"Still have a lot to do on the cost front, but long-term view on LNG is very positive. New LNG projects are required by 2023."**
- **"A lot of compelling reasons for Canada (projects) that they could compete. It makes sense over long term that a handful of B.C. projects may go forward."**

- **A recent (September 2017) assessment by one of BC Hydro's LNG market subscription services (IHS Markit) concludes:**

[redacted]

[redacted] **A review of a B.C. LNG export project database (as of September 2017) provided by another LNG market subscription service (Bloomberg) shows** [redacted] **Their earlier market reference forecast used to inform the Current Load Forecast assumed** [redacted] **) would be developed.** [redacted]

- **A recent (Spring 2017) assessment by another of BC Hydro's subscription services (ABB) that does not report specific B.C. LNG project expectations, but projects aggregate export tonnage, forecasts** [redacted]

- **"The key to our call is that a massive natural gas demand surge has started and will lead to world LNG markets being corrected closer to 2020 that the current conventional wisdom of closer to 2025. Shell's LNG head Maarten Wetselaar is quoted as saying 'Actually, over the last 18 months every LNG cargo that could technically be produced in this world has been produced and has found a well paying customer. So this market is more in balance than people perhaps perceive. Stream Asset Financial Management LP, September 20, 2017. (http://www.streamasset.ca/blog/2017/09/20/shell-every-lng-cargo-that-could-technically-be-produced-in-this-world-has-been-produced-and-has-found-a-well-paying-customer/#more-435)**

- **"Recent LNG project cancellations are not an indication that other projects in Canada are not competitive and will not be built, Western Canada Gas Monetization Group senior vice president Bill Gwozd said. 'The idea that LNG on the West Coast won't go forward is not true,' he said. 'While projects have been cancelled in the short-term, in the medium to long-term, worldwide demand for LNG will rise even as other gas exporting nations exhaust their supplies of natural gas', he said." (Globe and Mail, Kitimat still has sights set on LNG plants. September 22, 2017)**

**In summary, BC Hydro believes the market's view, on balance, remains largely unchanged from when the Current Load Forecast was developed; while there remains significant uncertainty, global LNG demand will continue to growth and there is opportunity for B.C. LNG.**

**Project-Specific Justification**

**One major justification for including the three LNG projects in the Current Load Forecast is the fact they are requesting electricity service. Service requests from industrial sector customers, including LNG, are generally included in our industrial load forecast.**

**LNG Canada executed a Load Interconnection Agreement, an Electricity Supply Agreement and a Studies Agreement in November 2014. We have completed a system impact study and are currently doing additional study work pursuant to those agreements.**

**Woodfibre LNG first requested electricity service in 2013 and has since been working with BC Hydro to define its requirements. Two partial system impact studies have been**

**completed and BC Hydro is currently waiting for further direction pending from Woodfibre pending completion of their Front End Engineering Design work.**

**FortisBC is currently commissioning Phase 1 of its LNG expansion project at Tilbury Island and is actively seeking new customers that would support further expansion of the facility. BC Hydro completed a system impact study for Phase 2 and Phase 3 in 2015.**

**Apart from ongoing work each of the project proponents have been doing with BC Hydro, there have been recent public statements which demonstrate the proponents' continued expectations that their projects will proceed. Each of these projects has also achieved significant regulatory and other project development milestones. These milestones and various public statements are summarized below.**

**LNG Canada**

- **Regulatory approvals and other project developments include:**
  - **Fourty-year export license issued May 27, 2016;**
  - **Provincial Environmental Assessment Certificate issued June 2015; amended August, 2016.**
  - **Federal Environment Assessment Decision Statement issued June 2015;**
  - **Facility Permit issued January 2015;**
  - **TransCanada Pipeline Coastal GasLink provincial Environmental Assessment Certificate issued in October 2014;**
  - **Project receives the last two of ten pipeline and facilities permits in May 2016; and**
  - **Saulteau First Nations and the B.C. Government reach benefits agreement in November 2016. Other agreements between Indigenous Peoples and the B.C. Government with respect to the Coastal GasLink pipeline project can be found at: http://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/consulting-with-first-nations/first-nations-negotiations/natural-gas-pipeline-benefits-agreements.**
- **"A $40 billion liquefied natural gas plant proposed for Kitimat is still very much alive, says the CEO of LNG Canada, but senior governments may need to address tax competitiveness before Shell and its three partners can make a final investment decision….**

**'I actually believe that B.C. will have an LNG industry, that there is societal support for an LNG industry from B.C. and … I believe specifically the LNG project can and will happen in B.C.' Andy Calitz told Business in Vancouver, following an address to the Greater Vancouver Board of Trade (GVBOT) Friday, September 22….**

**Michelle Mungall, the NDP's new minister of Energy, Mines and Petroleum Resources, who met one-on-one with Calitz earlier in the day, seemed to share Calitz's optimism, and said her government is considering some of the concerns the consortium — Shell, Mitsubishi, KOGAS and PetroChina — have expressed about moving forward….**

**Calitz said the Petronas and Nexen decisions have both positive and negative implications for the LNG Canada project. 'It strengthened the voices of both the critics and naysayers that say there will be no LNG from B.C. or there should be no LNG from B.C.,' Calitz said. On the positive side, Calitz said that 40 contractors that are bidding on contracts to build the plant now have less competition for scarce skilled labour." (Business in Vancouver, September 25, 2017).**

- **"Total project expenditures to date are several times the estimated total cost of the Vancouver Art Gallery redesign project" (Susannah Pierce, Director External Relations, LNG Canada. Speech delivered at Walrus Talks on June 8, 2017).[1]**

- **"LNG Canada spokesperson Susannah Pierce said demand is currently growing at a rate of five percent per year and there will be an opportunity for LNG shipments from Canada to find markets after 2022. So when we think about LNG Canada, we are anticipating that we need to have this project sanctioned in such a time that we can meet that new wave of demand, she said, adding the project would likely take four to five years to complete. Pierce confirmed the company is currently decommissioning and dismantling the old Methanex Corp. Facility in Kitimat, where LNG Canada's project is located, and the project will be ready for construction as soon as the owners make a decision." (Globe and Mail, September 22, 2017. Kitimat still has sights set on LNG plants).**

- **Petronas is considering acquiring a minority stake in the LNG Canada project. The company is also said to be exploring whether it is viable to transport gas from B.C. to the U.S. Gulf Coast through existing pipelines. https://beta.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/petronas-considers-acquiring-minority-stake-in-lng-canada/article36050004/?ref=http://www.theglobeandmail.com&**

**Woodfibre LNG**

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[1] **The estimated cost of the Vancouver Art Gallery redesign is $350M. http://www.cbc.ca/news/canada/british-columbia/vancouver-art-gallery-new-design-1.3248360.**

- **Regulatory approvals and other project developments include:**
  - **Fourty-year export license issued June 5, 2017;**
  - **Provincial Environmental Assessment Certificate issued October 2015;**
  - **Federal Environment Assessment Decision Statement issued March 2016;**
  - **Front End Engineering and Design contracts issued in October 2016;**
  - **Woodfibre LNG submitted an application to amend its Environmental Certificate to reflect design changes in February 2017; and**
  - **Provincial Environmental Assessment Certificate issued for FortisBC Eagle Mountain - Woodfibre Gas Pipeline Project in August 2016.**
- **On November 4, 2016 Woodfibre LNG announced that it its parent company, Pacific Oil & Gas Limited, has authorized the funds necessary for the Woodfibre LNG project to proceed. https://www.woodfibrelng.ca/parent-company-authorizes-woodfibre-lng-to-proceed-with-project/.**
- **"Despite the announcement this week that Petronas' Pacific NorthWest LNG megaproject is no longer going forward, the vice president of the Woodfibre LNG project near Squamish, B.C., is confident its project will still go through." http://www.cbc.ca/news/canada/british-columbia/woodfibre-lng-project-confident-it-will-move-forward-despite-pacific-northwest-setback-1.4224156.**
- **FortisBC is continuing to work on design and permitting of the Eagle Mountain to Woodfibre Gas Pipeline project. This project is a 47 kilometre expansion of the existing FortisBC pipeline system to deliver gas to the Woodfibre LNG facility in Squamish. In June 2017, FortisBC and Woodfibre LNG celebrated the opening of their Squamish community office. https://talkingenergy.ca/index.php/project/eagle-mountain-woodfibre-gas-pipeline-project.**

**Fortis BC Tilbury LNG**

- **Regulatory approvals and other project developments include:**
  - **Twenty-five-year export license issued May 26, 2016;**
  - **Provincial and federal environmental assessment approvals not required;**
  - **Facility permit issued; and**

- **WesPac Midstream's proposed LNG Marine Jetty at Tilbury Island received approval of the Application Information Requirements (AIR) from the British Columbia Environmental Assessment Office (BC EAO) on November 29, 2016. The supply of LNG for the Tilbury Marine Jetty will come via a pipeline from the existing adjacent FortisBC Tilbury LNG Plant.**

**<u>Response to LNG project-specific information requests</u>**

- **BC Hydro confirms FortisBC Tilbury, LNG Canada and Woodfibre LNG loads and (peak) demands are the total expected electricity loads and (peak) demands from these projects and are not probability weighted amounts.**

- **The unweighted load and demand schedules to each of the FortisBC Tilbury LNG Phase 2 project, the Woodfibre LNG project and the LNG Canada project included in the Current Load Forecast and revised outlook are provided in the following table.**

**Table 1 LNG Project Volumes Included in Current Load Forecast and Revised Outlook**

| GWh/year | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LNG Canada Revised | [redacted] | | | | | | | | | | | | | | | | | | |
| LNG Canada Current Forecast | | | | | | | | | | | | | | | | | | | |
| Difference (GWh) | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| GWh/year Ph 1 | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| FortisBC Tilbury LNG Revised | 22 | 64 | [redacted] | | | | | | | | | | | | | | | | |
| FortisBC Tilbury LNG Current Forecast | 139 | 139 | | | | | | | | | | | | | | | | | |
| Difference (GWh) | (116) | (75) | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| GWh/year Ph 2 | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| FortisBC Tilbury LNG Phase 2 Revised | [redacted] | | | | | | | | | | | | | | | | | | |
| FortisBC Tilbury LNG Phase 2 Current Forecast | | | | | | | | | | | | | | | | | | | |
| Difference (GWh) | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| GWh/year | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| Woodfibre Revised | [redacted] | | | | | | | | | | | | | | | | | | |
| Woodfibre Current Forecast | | | | | | | | | | | | | | | | | | | |
| Difference (GWh) | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| MW | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| LNG Canada Revised | [redacted] | | | | | | | | | | | | | | | | | | |
| LNG Canada Current Forecast | | | | | | | | | | | | | | | | | | | |
| Difference (MW) | - | - | - | [redacted] | | | - | - | - | - | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| MW Ph 1 | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| FortisBC Tilbury LNG Revised | 18 | 18 | [redacted] | | | | | | | | | | | | | | | | |
| FortisBC Tilbury LNG Current Forecast | 18 | 18 | | | | | | | | | | | | | | | | | |
| Difference (MW) | - | - | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| MW Ph2 | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| FortisBC Tilbury LNG Phase 2 Revised | [redacted] | | | | | | | | | | | | | | | | | | |
| FortisBC Tilbury LNG Phase 2 Current Forecast | | | | | | | | | | | | | | | | | | | |
| Difference (MW) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | |
| MW | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
| Woodfibre Revised | [redacted] | | | | | | | | | | | | | | | | | | |
| Woodfibre Current Forecast | | | | | | | | | | | | | | | | | | | |
| Difference (MW) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

- **Regarding the difference in the load schedules provided in Tables J-8 and J-9 and K-2, Tables J-8 and J-9 show FortisBC Tilbury and LNG Canada loads. The reason for the difference in the total load provided in Table K-2 is partially the Woodfibre LNG load, but also an adjustment to account for transmission system losses.**

**Other Relevant Considerations**

**The following additional considerations are relevant to how LNG and associated upstream gas production load is reflected in its load forecast.**

- **The Current Load Forecast is a small portion of the overall B.C. LNG-related potential load and associated upstream natural gas potential. At the time the Current Load Forecast was developed there were 19 LNG project proposals of which 18 had export licenses. Only three projects requesting electricity service from BC Hydro, of which only one of these projects has a material impact on BC Hydro's electrified upstream gas production loads, are included in the Current Load Forecast. In terms of associated upstream natural gas potential, the Current Load Forecast risk-adjusted customer requested load by approximately 40 per cent in F2030. In other words, only 40 per cent of customer requested load was represented in F2030 after being discounted for timing and/or completion risk.**

- **BC Hydro is currently undertaking feasibility studies for another large LNG project, which is not included in its Current Load Forecast.** [redacted]

- **Since the Current Load Forecast was completed there has been increased activity and interest among B.C. gas producers to supply US-based LNG production. This activity suggests future growth in the upstream gas production may be less dependent on B.C. LNG project development.**

- **The Deloitte report appears to overstate the upstream gas impacts in the event no LNG projects proceed. Specifically, some upstream gas production and processing facilities identified as LNG-dependent in BC Hydro's load forecast have been in operation for a number of years already and are expected to continue regardless of whether the downstream LNG export projects materialize. This results in an overstatement of the impact of a "no LNG" scenario by approximately 276 GWh/35 MW. It should not be assumed that the facilities would shut down after having been in operation independent of LNG development for some time.**

**(2) Other Industrial (Transmission) Load-Related**

**The table below provides the estimated effect of a change in industrial load probability weightings from what is assumed the Current Load Forecast and the results of the subsequent assessment of industrial transmission account developments that was provided in Appendix J of BC Hydro's Site C submission. The table also provides the qualitative rationale. BC Hydro notes that the probability weightings are themselves a risk assessment – in other words, most of the probability adjustments are due to material advancements (i.e. increased likelihood of proceeding) in new project development or, in the case of forestry sector pulp mills, a reduced or increased closure risk due to market conditions.**

**For example:**

- **Projects which are assigned 100 per cent probability are generally in production or under construction and have a low perceived probability of shutdown in the future.**
- **Projects with lower than 100 per cent probability incorporate various risks depending on whether they are new projects or existing facilities.**
    - **For new projects, the risk assessments are based on its stage of development (e.g., environmental approvals/permits, financing, market outlook, stage in interconnections process, likelihood of taking electricity supply from BC Hydro, etc,).**
    - **For existing facilities, lower than 100 per cent probability incorporates an assessment of closure risks or likelihood of curtailed production.**

**BC Hydro also notes that in several cases the increase in load is not related to a change in probability, but to a change in production capacity. For example, two mines added electrical powered equipment which resulted in a permanent increase in load relative to the Current Load Forecast.**

**In BC Hydro's view, the request to assign a risk level in addition to our probability weightings is redundant (i.e., revising a project's probability weighting from 50 per cent to 90 per cent inherently means the risk the load will not materialize is significantly reduced). For the purpose of this response, BC Hydro assumes the requested risk assessment is to identify future risks which could result in lower probability weightings than what has been currently assessed. We note that, while the question refers only to downside risk there is upside potential in several of these facilities due to enhanced production or lower risk of closure due to improved market conditions.**

**Table 2 Summary of Probability Assessments Used to Develop Table 11 in Appendix J**

| **Large Industrial (Transmission)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Operational Probabilities** | | | | | | |
| | **Revised Forecast (%)** | | | **Current Load Forecast (%)** | | | **Reasons for change in Assessment and Potential Future Downside Risks** |
| | 0-3 years | 4-10 years | 11-20 years | 0-3 years | 4-10 years | 11-20 years | |
| **Forestry** | | | | | | | **Revision Reasons:**<br>-Major upgrade at mill<br>- Change in PST treatment<br>- Plant closure<br>**Downside Risk:** Low<br>-Halt major upgrade |
| [redacted] | 100% | 100% | 100% | 65% | 36% | 35% | [redacted] |
| [redacted] | 100%) | 100% | 100%) | | | | [redacted] |
| [redacted] | 0% | 0% | 0% | 100% | 100% | 100% | [redacted] |

| **Large Industrial (Transmission)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Operational Probabilities** | | | | | | |
| | **Revised Forecast (%)** | | | **Current Load Forecast (%)** | | | **Reasons for change in Assessment and Potential Future Downside Risks** |
| | 0-3 years | 4-10 years | 11-20 years | 0-3 years | 4-10 years | 11-20 years | |
| **Oil & Gas** | | | | | | | **Revision Reasons:**<br>-Plant construction completions and<br>- Electrification agreements. . .<br>**Downside Risks:** (Low likelihood)<br>-Gas prices take a sustained fall<br>- Gas liquids prices take a sustained fall<br>- Condensate prices take a sustained fall<br>- Light oil prices take a sustained fall<br>**Long Term Mitigating Risk Factors:**<br>- Reduced exposure to carbon tax costs due to electrification<br>- Low cost competitive advantage of Montney Basin over other North American plays. |
| [redacted] | 100% | 100% | 100% | 81% | 81% | 81% | [redacted] |
| [redacted] | 100% | 100% | 100% | 72% | 72% | 72% | [redacted] |
| [redacted] | 100% | 100% | 100% | 63% | 63% | 63% | [redacted] |

**Large Industrial (Transmission)**

| | Operational Probabilities | | | | | | |
|---|---|---|---|---|---|---|---|
| | Revised Forecast (%) | | | Current Load Forecast (%) | | | Reasons for change in Assessment and Potential Future Downside Risks |
| | 0-3 years | 4-10 years | 11-20 years | 0-3 years | 4-10 years | 11-20 years | |
| [redacted] | 80% | 80% | 80% | 63% | 63% | 63% | [redacted] |
| [redacted] | 100% | 100% | 100% | 50% | 50% | 50% | [redacted] |
| [redacted] | 100% | 100% | 100% | 5% | 16% | 20% | [redacted] |
| [redacted] | 100% | 100% | 100% | 50% | 80% | 100% | [redacted] |
| [redacted] | 100% | 100% | 100% | 50% | 50% | 50% | [redacted] |
| [redacted] | 100% | 100% | 100% | 5% | 5% | 5% | [redacted] |

**Large Industrial (Transmission)**

| | Operational Probabilities | | | | | | |
|---|---|---|---|---|---|---|---|
| | Revised Forecast (%) | | | Current Load Forecast (%) | | | Reasons for change in Assessment and Potential Future Downside Risks |
| | 0-3 years | 4-10 years | 11-20 years | 0-3 years | 4-10 years | 11-20 years | |
| [redacted] | 50% | 50% | 50% | | | | [redacted] |
| [redacted] | 50% | 50% | 50% | | | | [redacted] |
| [redacted] | | | | | 15% | 15% | [redacted] |
| [redacted] | 75% | 75% | 75% | 10% | 10% | 10% | [redacted] |
| [redacted] | 0 | 0% | 0% | 90% | 90% | 90% | [redacted] |

| **Large Industrial (Transmission)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Operational Probabilities** | | | | | | |
| | **Revised Forecast (%)** | | | **Current Load Forecast (%)** | | | **Reasons for change in Assessment and Potential Future Downside Risks** |
| | 0-3 years | 4-10 years | 11-20 years | 0-3 years | 4-10 years | 11-20 years | |
| **Mining** | | | | | | | **Revision Reasons:**<br>- Closures, equipment upgrades, revised closure date, reaching production status, permit renewal.<br><br>**Downside Risk:**<br>- commodity price risk<br>- accidents<br>- regulatory risk<br>- financing<br>- ore reserve risk |
| [redacted] | 100% | 100% | 0% | 50% | 50% | 0% | [redacted] |
| [redacted] | 100% | 100% | 100% | 100% | 100% | 100% | [redacted] |
| [redacted] | 100% | 100% | 0% | 100% | 100% | 0% | [redacted] |
| [redacted] | 100% | 0% | 0% | 100% | 0% | 0% | [redacted] |

| **Large Industrial (Transmission)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Operational Probabilities** | | | | | | |
| | **Revised Forecast (%)** | | | **Current Load Forecast (%)** | | | **Reasons for change in Assessment and Potential Future Downside Risks** |
| | 0-3 years | 4-10 years | 11-20 years | 0-3 years | 4-10 years | 11-20 years | |
| [redacted] | 100% | 100% | 100% | 75% | 75% | 75% | [redacted] |
| **Others** | | | | | | | **Revision Reason:**<br>-Closures<br>Downside risk:<br>- economic conditions in the specific subsectors |
| [redacted] | 0% | 0% | 0% | 5% | 5% | 5% | [redacted] |
| [redacted] | 0% | 0% | 0% | 100% | 100% | 100% | [redacted] |
| [redacted] | 0% | 0% | 0% | 100% | 100% | 100% | [redacted] |

**(3) Assessment of completion and timing risk for LNG and other industrial projects**

**The information request asks BC Hydro to explain how the completion risk and, separately, the timing risk are factored into BC Hydro's Current Load Forecast in relation to each of the three LNG projects and other industrial projects and customers included in BC Hydro's Current Load Forecast. The information request also asks BC Hydro to identify, explain and justify the differences.**

**BC Hydro's large industrial sector load forecast methodology includes production forecasts, electric intensity (i.e., kWh/unit of production) and probability weightings. The probability weightings represent the risk assessment of future expansion or contraction, or the likelihood of previous trends in sales continuing.**

**In terms of risk types for the large industrial customers, BC Hydro quantifies two components of risk: timing and completion. Timing risk occurs when there is**

**uncertainty over which year a plant may open. In quantifying this in the forecast, an expected plant load is phased-in over a number of years. This duration is determined by utilizing various information sources (customers, Key Account Managers, load interconnections and third party market intelligence). This technique is applied across most of the industrial sectors.**

**Completion risk encompasses the probabilities associated with a plant starting or closing. Quantifying starting or closing probabilities is more complicated. Conceptually, both plant and market expectations need to be considered. The process for determining these probabilities differs between sectors. The process for assigning customer starting and closing probabilities ranges from using consultants that have the predominant influence over the probability value (as in the case of the forestry sector), to BC Hydro developing internal models (as in the case of upstream natural gas plants). In the case of upstream natural gas plants, the starting risk is actually a combination of a start-up probability and an electrification probability.**

**For upstream natural gas customers with timing and completion risks the overall probability weighted assessment consists of three separate probabilities: a multi-year probability (for timing risk), a start-up probability and an electrification probability (for completion risk). For the forestry and mining customers, the timing and completion risks are generally assessed together to form a multi-year probability weighting.**

**As noted in BC Hydro's F2017 - F2019 Revenue Requirements Application, the forecasting of electrified LNG plants loads has been approached differently in the Current Load Forecast. The sector is unique in that it is not yet developed, there are only three proponents that are proposing to electrify from the grid (therefore not allowing for confidential aggregation of a probabilistic load forecast) and is of keen public interest. For these reasons, BC Hydro had decided to transparently include the volume of load which these proponents have announced will be supplied by BC Hydro (and for which BC Hydro has service requests) and the load estimates and in-service dates are based on publically available information.**

**Since the upstream oil and gas sector load forecast methodology incorporates a probability weighted assessment approach, BC Hydro developed a probability-weighted view of potential LNG projects (both those requesting service and those not requesting service) as drivers of the upstream gas production. These probability-weighted assessments incorporate both completion and timing risk and are provided in the following table.**

**Table 3 Summary of LNG Project Probability Weightings Used to Estimated Probability Weighted Upstream Gas Production and Electricity Load Forecasts**

| Project | F2020 (% | F2021 (%) | F2022 (%) | F2023 (%) | F2024 (%) | F2025 (%) | F2026 (%) | F2027 (%) | F2028 (%) | F2029 (%) | F2030 (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

**As noted in the Deloitte Report, BC Hydro's upstream gas production forecast is based on the assumption that LNG Canada will occur with [redacted].[2] The Deloitte Report concludes this assumption is overly optimistic. BC Hydro disagrees. While BC Hydro agrees there is there is risk and uncertainty associated with BC LNG projects, the LNG Canada, Woodfibre LNG and FortisBC Tilbury Phase 2 probability-weighted completion and timing assumptions used to develop the upstream gas production forecast are reasonable long term planning assumptions. These assumptions continue to be reasonable in light of the macro-economic and project-specific evidence presented above.**

**In contrast, the Deloitte Report's alternative scenario (which removes the LNG Canada load from the Current Load Forecast entirely) is overly pessimistic as demonstrated by the information above. However, BC Hydro recognizes there is considerable uncertainty associated with LNG and the associated upstream oil and gas loads. We provide the following figure to demonstrate that the need without any LNG or LNG-related upstream oil and gas does not materially change the timing of energy shortfall when compared to the "without LNG" timing provided in Figure 12 of Chapter 5 of our August 30 Filing. Further, the results provided in the "Base Case Less LNG Loads" sensitivity to our portfolio PV analysis in Table 20 of our August 30 Filing shows that Site C is cost-effective without any LNG or LNG-related upstream oil and gas.**

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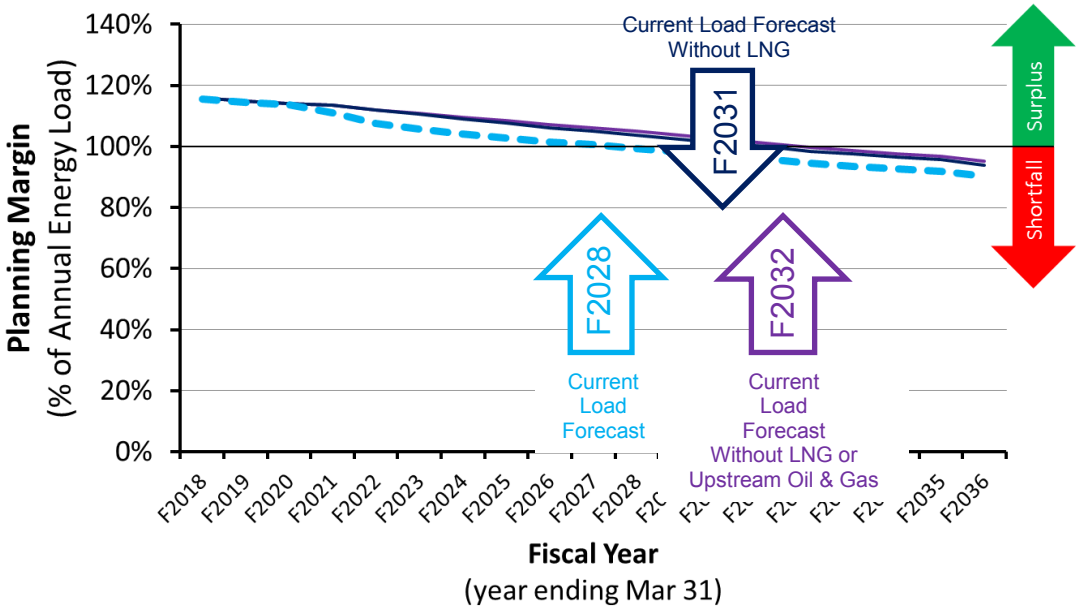
[2] **As noted in the IR, market forecasts generally expect new LNG will be needed to supply demand by the mid-2020s.**


Planning Margin
(% of Annual Energy Load)
140%
120%
100%
80%
60%
40%
20%
0%
Current Load Forecast
Without LNG
F2031
F2028
F2032
Current
Load
Forecast
Current
Load
Forecast
Without LNG or
Upstream Oil & Gas
Surplus
Shortfall
F2018
F2019
F2020
F2021
F2022
F2023
F2024
F2025
F2026
F2027
F2028
F2035
F2036
Fiscal Year
(year ending Mar 31)

**18.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 61**

2.18.1 The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income:

- Please address the differences noted by Deloitte in its Load Forecast Assessment related to GDP and disposable income. Please obtain whatever information from Deloitte that BC Hydro deems necessary in order to respond to this request.

**RESPONSE:**

**Deloitte acknowledges in its report that it has not attempted to determine which of Conference Board of Canada's (CBoC) or Robert Fairholm Economic Consultants economic forecast is likely to be more accurate. Rather, Deloitte only compares the outcomes implied by two different forecasts over the same time period. BC Hydro has alternately used Robert Fairholm and the CBoC to undertake the detailed econometric modelling in B.C. to provide BC Hydro with detailed, regional economic growth assessments that then drive the Statistically Adjusted End-Use (SAE) forecasts. BC Hydro in general observes that CBoC work would have been a high level assessment whereas Fairholm was more detailed work. BC Hydro also notes that the overall load impact from the varied GDP assumptions are not very significant. Details are shown below.**

***Approach to Assessing Differences Between Fairholm and Conference Board Forecasts***

**In order to answer this information request and BCUC IR 2.18.2, BC Hydro purchased a copy of the report entitled, "PROVINCIAL OUTLOOK 2016 Long-Term, Economic Forecast" from the CBoC. Deloitte confirmed in an email exchange with BC Hydro that the total B.C. provincial real GDP history and forecast and the total B.C. provincial household disposable income history and forecast, which are found on page 119 and 120 of the CBoC report, were the two variables that Deloitte used to formulate their comments in their September 8, 2017 Report. While the report is dated 2016, the date of the CBoC forecast in the report is December 11, 2015.**

**BC Hydro can only offer limited comments to compare and explain the differences between Robert Fairholm and CBoC GDP and disposable income projections. We outsource these forecasts to Robert Fairholm Economic Consultants given the specialized expertise and sophisticated models required for the analysis. It is not possible to assess the model, assumptions and inputs which generated the December 11, 2015 forecast based on the CBoC report.**

**The Robert Fairholm economic model is sophisticated. It simultaneously solves several hundred economic forecasting equations to generate a series of economic variables for 15 regions and the provincial economy including total provincial GDP. BC Hydro provided a high level model description and major input assumptions to the Commission as part of its F2017 - F2019 Revenue Requirements Application (i.e., Robert Fairholm July 2014 Report to BC Hydro in the response to BCUC IR 1.5.1, Exhibit B-9-2).**

***Real GDP Growth***

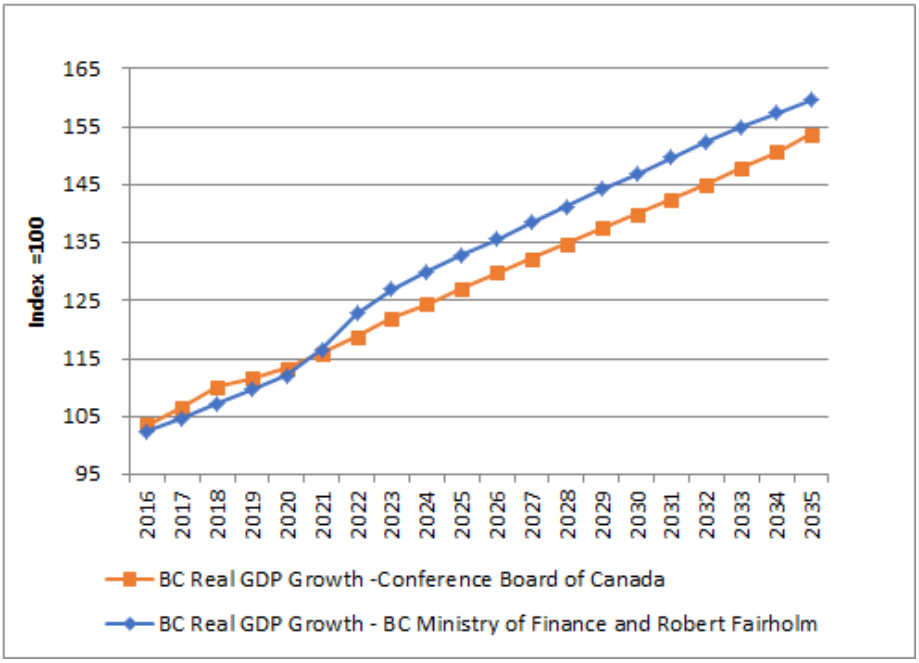
**The forecast of real GDP growth is only used to develop the Current Load Forecast light industrial manufacturing sector sales. This sector makes up only 5 per cent of the total system sales.**

**The figure below shows:**

**(i) The forecast of the real GDP growth from Table H-6, page 29, Appendix H of BC Hydro's August 30 Filing. The GDP growth forecast is based on projections from the Ministry of Finance for the first five years and then from Robert Fairholm's March 2015 economic forecast for all subsequent years; and**

**(ii) The 2016 CBoC December 2015 forecast of GDP growth. The GDP growth projections are indexed to 2015.**

**Figure 1 Real GDP Growth Forecast from CBoC and BC Ministry of Finance and Robert Fairholm**



**Differences in the GDP growth projections can arise from various factors, including:**

- **difference in model inputs;**
- **structural equations;**
- **solving methods; and**
- **whether the models are a top down model of the total economy or a series of various regional sub models that aggregate to a total provincial forecast.**

**In terms of specific input assumptions, the projected increase in real GDP after 2020 in the Robert Fairholm economic forecast is due to increased investment growth, particularly in the Northern Region, where it is anticipated most of the LNG export production and upstream gas production will take place. However, that investment and GDP increase does not translate into a one for one increase in overall total load growth. For further information on the GDP load impact of LNG and upstream gas production please refer to BC Hydro's response to BCUC IR 2.18.3.**

***Conference Board GDP Projection Does Not Show Recessionary Periods Either***

**One of Deloitte's critiques of BC Hydro's mid-forecast model (page 5) is that the model does not explicitly incorporate recessionary periods. Deloitte suggests that it is likely that such periods will occur over a 21-year horizon, based on the historical record. Others have submitted similar thoughts on reflecting future recessions in BC Hydro's mid forecast. In this regard it is also worth noting that, despite the difference in GDP growth projections in the table above, the CBoC GDP projection similarly shows no recessions (i.e., negative annual growth) occurring over the next 21 years.**

***Comparison of Forecast of Growth in Disposable Income***

**BC Hydro is unable to confirm differences noted by Deloitte on page 73 of its September 8, 2017 report, where Deloitte compared projections of growth rates of disposable income from the CBoC and Robert Fairholm.**

**Based on information provided by Deloitte in an email exchange, Deloitte compared a CBoC nominal dollar growth rate to a Fairholm's real dollar growth rate and determined that the real dollar Fairholm growth was higher than the CBoC nominal dollar growth from year six to year ten of the forecast period. BC Hydro's analysis of the data provided by Deloitte is shown in the figure below.**

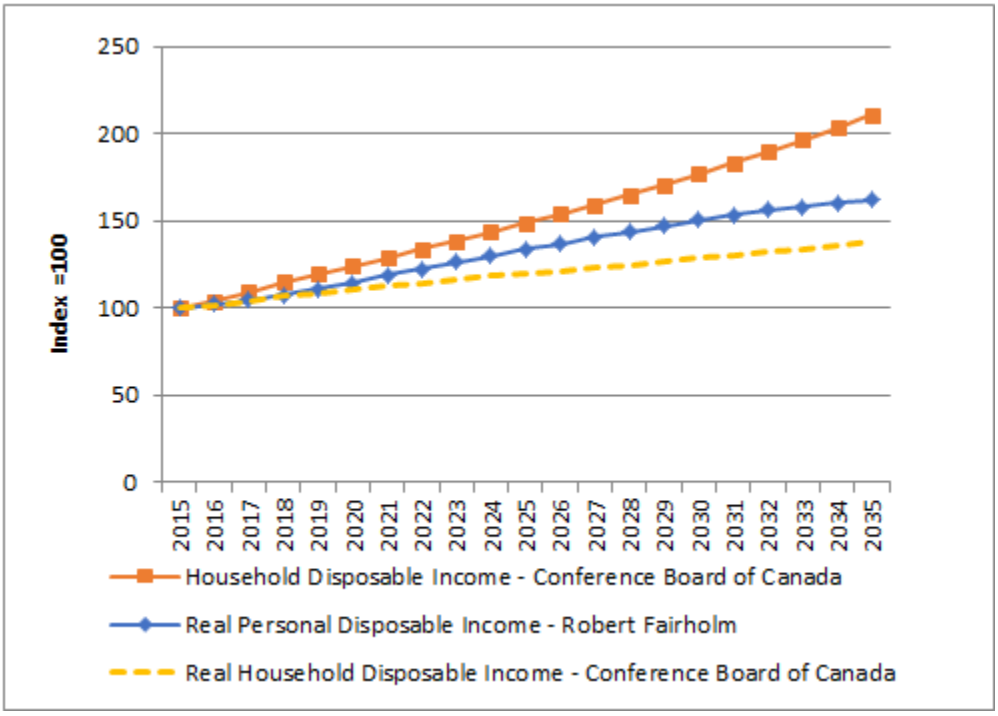
**The figure below shows:**

**(i) the forecast of growth in real personal disposable income for the BC Hydro service area from Table H-5, page 28, Appendix H of BC Hydro's August 30 Filing; and**

**(ii) the CBoC December 2015 projection of annual growth rates in household income in nominal dollars and real dollar terms as contained in its 2016 report as noted above.**

**The annual growth rates are indexed to a base year of 2015.**

**Figure 2 Disposable Income Forecasts from the CBoC and Robert Fairholm**




**If BC Hydro adjusts the CBoC's nominal dollar forecast of household disposable income based on the CBoC's Consumer Price Index of annual inflation rate as contained in its report we find the CBoC's projected annual growth rate is lower but more in line with that of Robert Fairholm's projection for real personal income for BC Hydro's service area.**

**BC Hydro uses Robert Fairholm's forecast of real personal disposable income growth for each of our four main service regions as inputs into each of our four regional residential SAE models in order to develop use per account projections for the residential sector. These regional income drivers are just**

**one of the several regional drivers of the models. The other drivers include people per account, temperature measured by heating and cooling degree days and average efficiency of end use of electricity and penetration or share of accounts that have those end uses.**

**While not all of the assumptions on disposable income in the CBoC report are transparent, we believe differences can be due to the following reasons:**

- ***Differences in the economic modelling of disposable income and differences in the definition of disposable income.*** **Robert Fairholm defines real personal disposable income via employment and wages, which determine labour income. Labour income plus non-labour income (government transfers and other non-labour income such as interest and dividend income) determine total personal income. Direct personal taxes are subtracted from personal income to determine disposable income. Consumer prices then determine real disposable income that is a primary determinant of household consumption expenditure. There is no definition of household income in the CBoC Report.**

- ***BC Hydro's forecast of disposable income is specific to BC Hydro service area:*** **BC Hydro's forecast above is an estimate at the total service area while CBoC is at the total B.C. provincial level. When developing BC Hydro's forecast it is necessary to have an income forecast tailored to each of BC Hydro's four service area regions.**

- ***BC Hydro's forecast of disposable income is in real dollars and Conference Board's estimate is nominal dollars*****. BC Hydro suggests a comparison that may isolate the modelling differences could be arrived at by establishing a common definition of disposable income, a common geographical boundary (i.e., total provincial vs total BC Hydro service area) and an inflation common deflator to compare real growth rates. Deloitte acknowledges that precise comparisons in forecasts are difficult given how they are reported.**

**18.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 61**

2.18.2 The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income:

- Please provide an analysis of the GDP and disposable income projections developed by RFEC compared to the Conference Board of Canada (CBoC) estimates and explain the reasons for significant differences in projections. In particular, please explain why the RFEC projection for GDP is not consistent with the CBoC's projections after the first five years.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.18.1.**

**18.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 61**

2.18.3 The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income:

- Please quantify the effect on BC Hydro's load forecast of reducing its GDP forecast to align with the CBoC's GDP projections.

**RESPONSE:**

**The Deloitte report identifies the CBoC's long-term provincial GDP forecast as an alternative to the Robert Fairholm provincial GDP forecast used by BC Hydro. While the Deloitte report does not examine which forecast is more likely to be accurate, it calculates the difference between the two GDP forecasts and applies BC Hydro's GDP elasticities[1], contained within the Monte Carlo simulation model, to estimate adjustments to residential, commercial and light industrial sector energy and peak load forecasts. The Deloitte report considers its results to be approximate and indicative of magnitude and direction only for the purpose of an alternative load scenario. In BC Hydro's view, the method used by Deloitte to adjust the energy forecast is:**

1. **overly simplistic relative to the comprehensive, industry standard models BC Hydro employs to develop its energy forecast; and**

2. **technically incorrect with respect to estimating peak demand.**

**As a result, the comparative GDP impact analysis presented in the Deloitte report significantly overestimates – *by six times* – the energy and peak load adjustments arising from using the CBoC's long-term provincial GDP forecast.**

***BC Hydro's Sophisticated Industry Standard Modelling Should Be Preferred to Deloitte's Oversimplified Approach***

**In addition to the individual large industrial account forecast, BC Hydro's mid-energy forecast consists of:**

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[1] **GDP elasticity is only one of many variables that are contained in the Monte Carlo simulation model used to produce the high and low bands not the mid forecast. Some other variables include the mid long-term GDP projection; weather variable expressed as heating degree days; and the high and low industrial load forecasts for the major sub-sectors which are key factors to the overall system uncertainty band.**

- **twelve individual SAE model forecasts;**
- **electric vehicle forecasts;**
- **light industrial forecasts (a portion of which is developed using an econometric model and portion of which is developed on an account-by account basis); and**
- **four separate industrial sector forecasts.**

**Of these models, only the "other manufacturing" portion of the light industrial sector (making up only 5 per cent of total system sales) model uses GDP as a direct input driver. While the residential and commercial models have economic input drivers (e.g., housing starts, employment, commercial GDP) that are related to provincial GDP, none use a single provincial GDP as a direct input driver to develop sales projection.**

**BC Hydro's distribution peak forecast (the combined impact of residential, commercial and light industrial sectors) involves an additional layer of modelling complexity which uses SAE energy forecasts as inputs to develop the distribution peak forecast. BC Hydro's load forecast methodologies are described in Appendix H of our August 30 Filing. The SAE models are considered industry best practice and both the Deloitte report and the GDS audit report conclude BC Hydro's historical forecasting accuracy in the residential and commercial sectors using these models has been good.**

**Deloitte's top-down adjustment assuming a single load driver (GDP) and GDP elasticities for the residential and commercial sectors is an oversimplification compared to the modelling sophistication used to develop those sector forecasts. As such, the results cannot be relied on to develop an alternative load forecast.**

***A More Appropriate Way to Align the Current Load Forecast With CBoC GDP Projections***

**A more realistic sensitivity analysis to the Current Load Forecast for the effects of a lower GDP forecast which align with the CBoC's GDP projections is to look at the load forecast modelling results that were undertaken as part of the fiscal 2017-2019 Revenue Requirements Application. As part of that proceeding, Robert Fairholm was asked to develop a comprehensive regional economic forecast and total GDP forecast assuming no B.C. LNG plants and associated upstream natural gas production are developed. BC Hydro ran the outputs of that alternative economic forecast in each of its residential, commercial and light industrial models and the results of this analysis was provided in BC Hydro's response to BCUC IR 3.342.2.2.1, Exhibit B-21.**

**The Deloitte report suggests this may be an appropriate comparison given the similarities between the CBoC's GDP forecast and the Robert Fairholm (No LNG)**

**GDP forecast. This comparison is represented in Figure 10 of the Deloitte report which is provided below.**

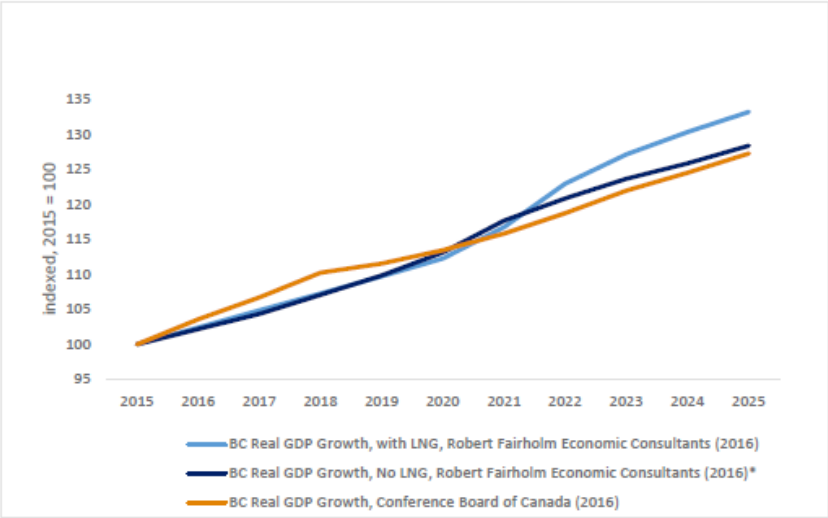


Figure 10: BC's Projected Real GDP Growth, with and without LNG

**The following table shows the difference in domestic sales (i.e., sales to all BC Hydro customers excluding losses) between the Current Load Forecast and the alternative (RFEC, no LNG) economic scenario forecast on a billed basis and after demand side management savings. The notes to the table below provide further commentary.**

| Fiscal Year | Difference (GWh) | Difference (%) |
|---|---|---|
| **F2017** | **(21)** | **-0.04** |
| **F2018** | **(44)** | **-0.09** |
| **F2019** | **(82)** | **-0.16** |
| **F2026** | **(265)** | **-0.40** |
| **F2036** | **(276)** | **-0.41** |

**Note:**

1. **The above differences were prepared with the same residential accounts forecast as that contained in the Current Load Forecast because aside from differences in housing starts in the Northern region, there were not significant differences in other parts of the BC Hydro's service area.**
2. **Aside from the simplifying assumption on residential accounts identified in Note 1, the differences above reflect the difference in the sales projection between the different economic forecasts when applied to the same mid-forecast models.**

**We also estimated the peak load impacts associated with the estimated energy impacts since the analysis done as part of the F2017 – F2019 Revenue Requirements Application was for energy only. BC Hydro estimated the peak impacts by applying an approximate distribution peak load factor (0.55) to the estimated energy reductions. This method of calculating peak impacts is the technically correct approach compared to Deloitte's methodology, which uses GDP elasticities contained in BC Hydro's Monte Carlo simulation model to adjust BC Hydro's peak mid-forecast. Deloitte's method overestimates the peak load impact.**

***Deloitte Applied the Peak Load Adjustment to the Wrong Sectors***

**It appears the Deloitte report's peak load adjustment was made *to the total system mid peak forecast* as shown in Figure 12 of their Report of September 8, 2017 and not just to the *distribution (residential, commercial and light industrial sector) peak load.* This exacerbates the inaccuracy of the Deloitte report estimated peak load adjustments because:**

**(i) it includes the large industrial sector peak load, which is estimated using a separate process that does not consider provincial GDP forecasts; and**

**(ii) the energy reduction suggested by Deloitte only applies to the residential and light industrial and commercial sectors.**

***Summary***

**Deloitte's approach overstates the reduction by a factor of six. When our analysis is used to align the Current Load Forecast with the CBoC's GDP projections, it results in a reduction in load that is substantially less than the reduction identified by Deloitte. Specifically:**

- **For fiscal 2026, BC Hydro estimates a 265 GWh energy reduction compared to about the 1,600 GWh reduction estimated by Deloitte (based on Deloitte's statements that residential load requirements would be 3.8 per cent lower by F2026, while those for the commercial and light industrial sector would fall by 3.6 per cent).**

- **For fiscal 2026, the 265 GWh reduction translates to about 55 MW capacity reduction in contrast to the Deloitte report approach which estimated a reduction of 425 MW to 435 MW. (based on Deloitte's statements of a reduction in system peak of 3.3 per cent to 3.4 per cent.**

**In summary, BC Hydro's estimates of energy and peak impacts with the detailed mid forecast methodology associated with Fairholm economic projection of No LNG, where the Fairholm GDP forecast is close to the alternative CBoC's provincial GDP forecast, is more realistic given industry standard models**

**compared to the Deloitte report's overly simplified (and incorrectly applied in the case of the peak load adjustment) approach. By comparison the GDP impact analysis presented in the Deloitte report significantly overestimates the energy and peak load adjustments arising from using the CBoC's long-term provincial GDP forecast.**

**18.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 61**

2.18.4 The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income:

- Please provide data/information on the historical accuracy of both the CBoC's and RFEC's GDP forecasts and comment on which of these parties' forecasts has historically been more accurate.

**RESPONSE:**

**BC Hydro's ability to undertake a direct comparison of CBoC and Robert Fairholm economic forecasts is largely limited to the periods for which we retained these respective consulting services to develop economic inputs to our load forecast models. The analysis we have been able to perform, which is described below, yields the following conclusions:**

- **There are too few variances over the period shown to make a conclusion about the long-term accuracy on the various projections from Robert Fairholm and the CBoC.**
- **Of the various sources that BC Hydro has used to develop the load forecast, none have factored recessions into their economic forecasts. BC Hydro also believes this to be the case for each of the forecasters on the BC Economic Council that provide input to the BC Ministry of Finance's five-year economic projections[1]. Forecasts of GDP growth, housing starts and employment growth that were developed after the recession generally anticipated a strong recovery. However, actual economic recovery occurred at a slower pace relative to the forecasts.**
- **The Ministry of Finance's forecasts of real GDP growth are fairly accurate aside from the forecast made prior to the last recession in BC. The Ministry of Finance forecasts are a reliable input to use in BC Hydro's load forecast.**

***Chronology of the External Economic Forecasts***

**The following chronology on the external economic forecasts used by BC Hydro is provided to assist in comparing the accuracy of the Robert Fairholm forecasts with**

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[1] **An example of the GDP projections from the BC Economic Forecast council is provided on page 87 of the BC Ministry's of Finance February 16, 2016 Budget located at http://bcbudget.gov.bc.ca/2016/bfp/2016_Budget_and_Fiscal_Plan.pdf.**

**CBoC forecasts as applied in the development of BC Hydro's load forecasts over the past ten years:**

- **BC Hydro has used Robert Fairholm's regional and provincial economic forecast as well as the Ministry of Finance projection of real GDP growth to prepare its Current Load Forecast (prepared in May 2016).**

- **The same sources were used to develop BC Hydro's annual 2014 load forecast, which was in May 2015.**

- **For its annual load forecasts over the period from 2011 to 2013, BC Hydro used Ernie Stokes Economic Consulting services.**

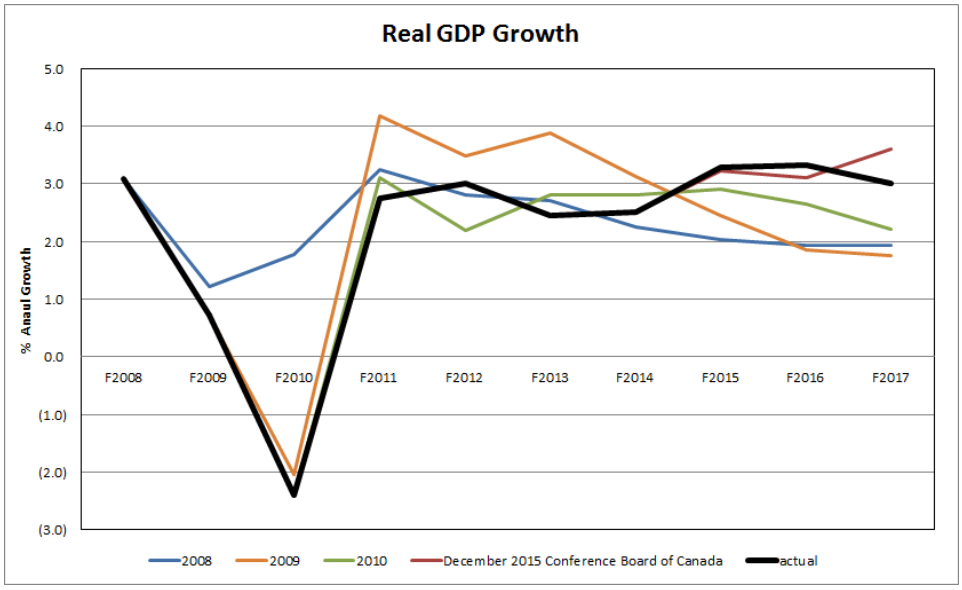
- **For its 2006 to 2010 annual load forecast, BC Hydro used the CBoC.**

**In addition, the Conference Board of Canada and Robert Fairholm Economic Consultant employ different methodologies and definitions for some economic drivers, such as retail sales, disposable income and commercial GDP.**

**Therefore, BC Hydro can only provide a comparison of historical and forecast of employment growth, real GDP growth and housing starts where the definitions are similar. BC Hydro purchased the CBoC 2015 economic forecast and received their permission to use the information for this response in order to permit comparison of the Robert Fairholm economic forecast used for the Current Load Forecast against the CBoC 2015 economic forecast used in the Deloitte Report,**

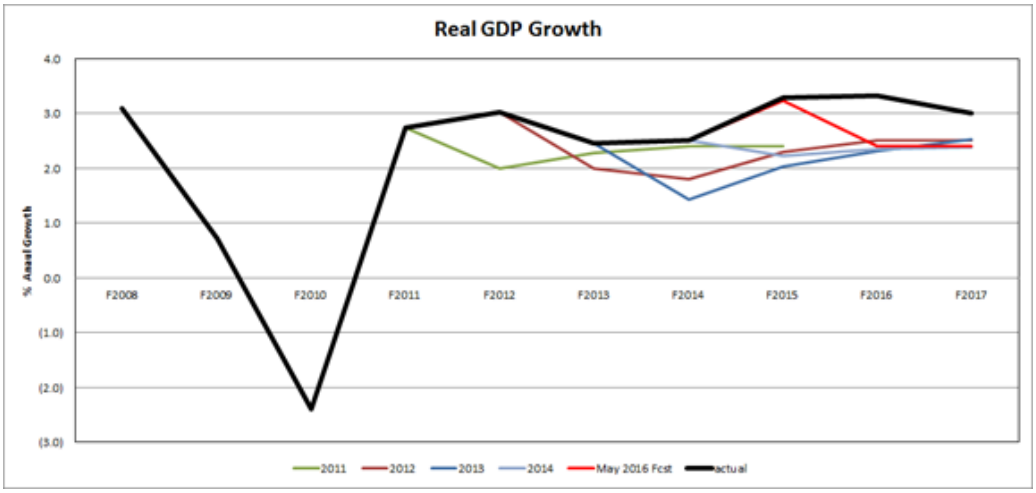
**We also note that for real provincial GDP growth projections, BC Hydro uses the BC Ministry of Finance forecast where available (over a period of five years) and these forecasts are included in the comparative results below. The figures below show various historical forecasts and actuals of various economic drivers used to develop the historical load forecasts.**

**Figure 1** **BC Real GDP Growth Comparison: Actuals Compared Against the Ministry of Finance and CBoC Projections used in the 2008-2010 Load Forecast Vintages and the Conference Board of Canada's December 2015 BC Provincial Forecast**



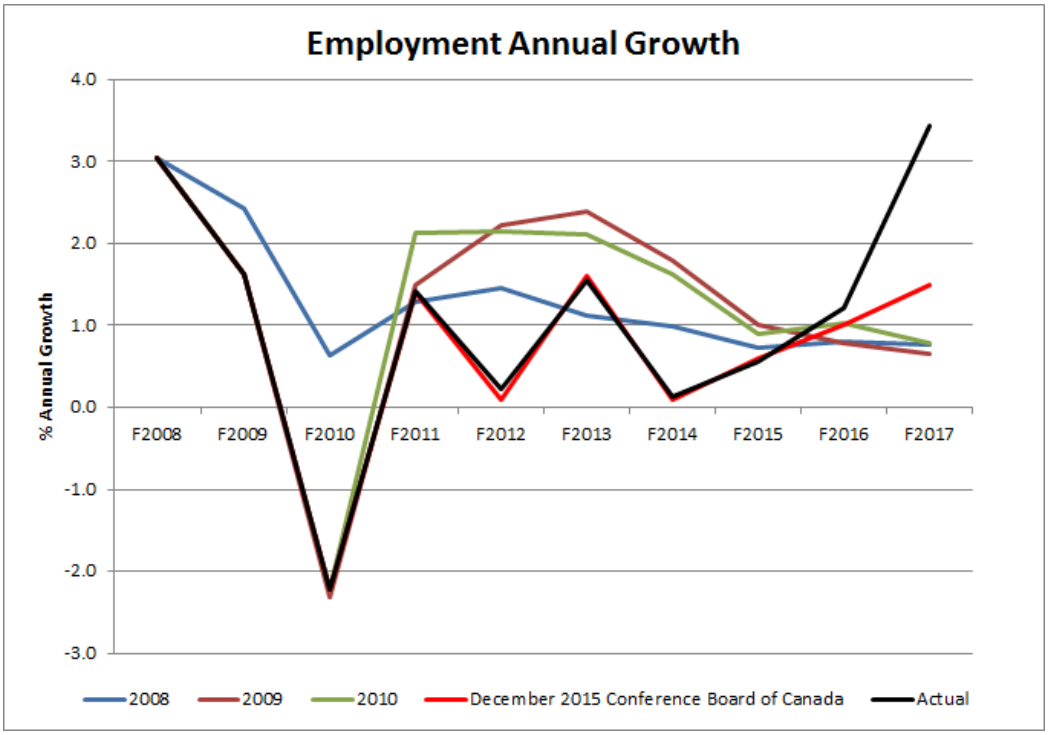

**The 2008 to 2010 GDP forecasts consist of short term projections from the BC Ministry of Finance followed by CBoC projections after the fifth year. The 2008 GDP forecast missed the recession and overestimated the actual recovery in GDP growth. The CBoC's 2015 forecast of real GDP growth was very close to actual growth.**

**Figure 2** **BC Real GDP Growth Comparison: Actuals Compared against BC Ministry of Finance Projections used the 2011- May 2016 Load Forecast Vintages**



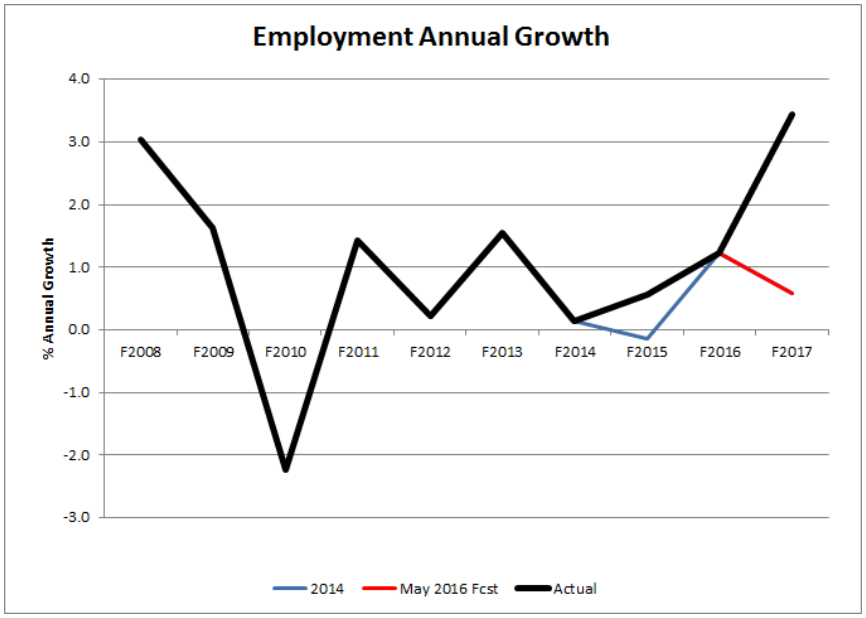
**The GDP forecasts in the figure above are from the BC Ministry of Finance as they are within the five year projection period. In general, the GDP forecasts are under the actual real GDP growth. However, they are also generally within a variance of about 1 per cent of actual growth. Recent forecasts have underestimated the strong GDP growth in B.C. We note that the recent actual GDP growth is closer to Robert Fairholm's projection of GDP growth near the middle years of the forecast period. during the period 2014 to 2016. In contrast to this, the CBoC's 2015 forecast, as shown in the previous graph, were fairly accurate over this time period. Note the 2011 forecast does not extend to 2016 because after the first few years the source of the GDP forecast is Ernie Stokes Economic Consulting Ltd.**

**Figure 3 Employment Growth Projection Comparison: Actuals Compared against and CBoC Projections used in the 2008-2010 Load Forecast Vintages and their December 2015 B.C. Provincial Forecast**



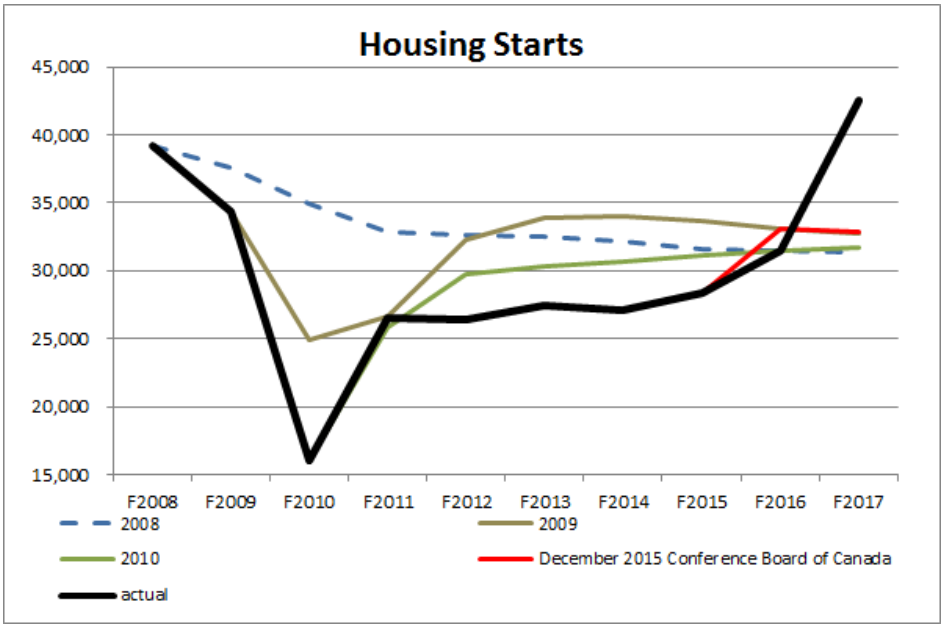

**The CBoC's employment growth forecasts were generally optimistic from 2008 to 2014 relative to actuals and it under-forecasted employment growth in 2015 and 2016.**

**Figure 4** **Employment Growth Projection Comparison: Actuals Compared against Robert Fairholm Economic Consulting Projections used in the 2014 and May 2016 Load Forecast Vintages**



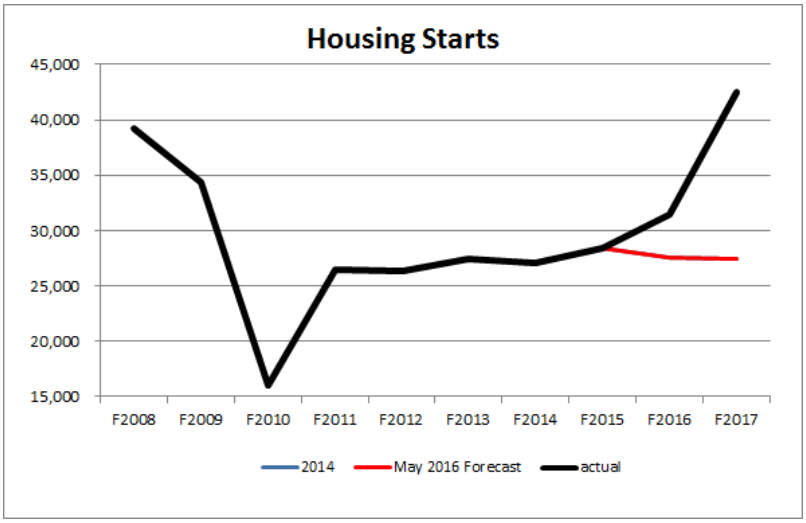

**Robert Fairholm's employment growth forecasts were very accurate for 2015 but under-forecasted actual employment growth in 2014 and 2016.**

**Figure 5** **Housing Starts Projection Comparison: Actuals Compared against CBoC Projections used in the 2008-2010 Load Forecast Vintages and their 2015 B.C. Provincial Forecast**



**The CBoC's forecast of total BC housing starts from 2008 to 2010 were generally above actual starts from 2008 to 2014, very accurate for 2015, and under forecasted starts for 2016.**

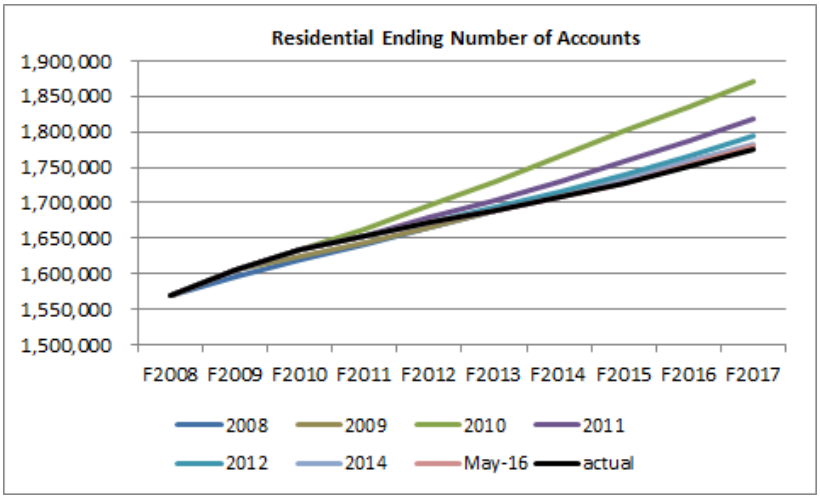
**Figure 6 Housing Starts Projection Comparison: Actuals Compared against Robert Fairholm Economic Consultant Projections used in the 2014 and May 2016 Load Forecast Vintages**




**Robert Fairholm under forecasted the number of starts in 2015 and 2016.**

**A forecast of housings starts is used to develop BC Hydro's residential accounts forecast. The figure below is historical accuracy of BC Hydro's residential accounts forecast over all periods.**

**Figure 7 Residential Account Forecast: Comparison of Actuals against BC Hydro Forecasts**



**Aside from the 2010 forecast, the residential account forecast is very close to the actual total ending number of residential accounts. BC Hydro uses a consultant's projection of housing starts forecast on a regional basis as an input to its accounts forecast model. However, we also review the model's account projections and may make adjustments depending upon the model's forecast of growth relative to short and near term actual account growth trends for the various regions.**

**Conclusions:**

- **There are too few variances over the period shown to make a conclusion about the long-term accuracy on the various projections from Robert Fairholm and the CBoC.**

- **Of the various sources BC Hydro has used to develop the load forecast, none have factored recessions into their economic forecasts. BC Hydro also believes this to be the case for each of the forecasters on the BC Economic Council that provide input to the BC Ministry of Finance's five-year economic projections. Forecasts of GDP growth, housing starts and employment growth that were developed after the recession generally anticipated a strong recovery. However, actual economic recovery occurred at a slower pace relative to the forecasts.**

- **The Ministry of Finance's forecasts of real GDP growth are fairly accurate aside from the forecast made prior to the last recession in B.C. The Ministry of Finance forecasts are a reliable input to use in BC Hydro's load forecast.**

**18.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 61**

2.18.5 The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income:

- Please explain what impact, if any, the recently announced halt to the Aurora LNG Project will have on GDP projections developed by RFEC. For the purposes of this response, please assume that the Aurora LNG Project will not proceed.

**RESPONSE:**

**BC Hydro confirms the Aurora LNG Project was not included as part of the input assumptions provided to Robert Fairholm Economic Consultants and therefore has no impact on the GDP projections provided by Robert Fairholm Economic Consultants.**

**19.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 64**

2.19.0 Regarding the appropriateness of BC Hydro's assumptions related to price elasticity and future rate increases, the Panel requests BC Hydro to respond to the following questions:

- Please provide a more detailed explanation as to how elasticity, a measure the Panel understands to be at the margin, is impacted by DSM.
- Please confirm, or explain otherwise, that BC Hydro has assumed zero real rate increases as part of its load forecast beyond 2024 (i.e. beyond the 2013 10 Year Rates Plan) and that any rate increases introduced between F2025 and F2036 would lower the Current Load Forecast. If confirmed, please explain the basis for and the reasonableness of this assumption.
- Please provide a detailed explanation of the risks which might prevent BC Hydro from achieving its projected zero real rate increases.

  The Panel also invites submissions from other parties to assist the Panel in assessing the appropriateness of the assumptions related to price elasticity and future rate increases.

**RESPONSE:**

- ***Please provide a more detailed explanation as to how elasticity, a measure the Panel understands to be at the margin, is impacted by DSM***

**Both customer response to electricity prices and Demand Side Management (DSM) programs reduce electricity consumption and influence future electricity demand. BC Hydro uses price elasticity of demand to estimate the reduction in load due to customers' response to electricity price increases alone (including both general rate increases and conservation rate structures). There are barriers to energy conservation other than affordability (such as lack of awareness, acceptability) that cannot be addressed through customers' response to price increases alone. We offer DSM programs and initiatives that when combined with customers' response to price increases help overcome these barriers. These energy savings are estimated separately and are included in BC Hydro's DSM Plan.**

**This response provides:**

- **a summary of BC Hydro's empirical studies on price elasticity;**

- **a discussion of the limitations of adopting elasticity estimates from other regions to modify the forecast load and then further subtracting BC Hydro's original estimate of DSM savings from the forecast load as has been suggested by some proceeding participants; and**

- **a discussion of BC Hydro's approach to updating our forecast if price elasticity were to change.**

**<u>Summary of BC Hydro's Empirical Studies on Price Elasticity</u>**

**BC Hydro has conducted a number of empirical studies of price elasticity for our customers. These are summarized below. All these studies set out to estimate price elasticity while controlling for the effects of DSM and other variables that influence electricity consumption in B.C.**

**The results of these studies show that BC Hydro customers' price elasticity has historically been modest compared to other jurisdictions. BC Hydro's longstanding involvement in DSM may be one reason for this modest price elasticity. For example, a residential customer who has undertaken several energy efficiency improvements with the assistance of a DSM program has fewer remaining opportunities to save electricity in their home and has a lower electricity bill than otherwise. In turn, they should be less responsive to electricity price increases than otherwise.**

- **BC Hydro verified residential customer, Step 2 price elasticity of demand for electricity of between -0.08 and -0.13. These price elasticity estimates include the response to general rate increases – assumed to be -0.05 – as well as the response to the Residential Inclining Block Step 2 price increases. The analysis used BC Hydro customer, DSM, electricity price and other data from 2004 to 2012. The study was documented in BC Hydro's Evaluation of the Residential Inclining Block Rate, which was provided as evidence in BC Hydro's 2015 Rate Design Application.**

- **BC Hydro has evaluated the Tier 2 price elasticity of industrial transmission service rate customers to be -0.16. The analysis used BC Hydro customer, DSM, electricity, price and other data from 2002 to 2009. The study was documented in the report titled Impact Evaluation of the Transmission Service Rate Milestone Evaluation Report dated October 2009. The results of this study have been shared with the Commission on several occasions, and were most recently referenced by the Commission in their document titled decision titled "Key Findings – Load Forecast" dated August 27, 2017, regarding the F2017-F2019 Revenue Requirements Application.**

- **BC Hydro conducted a study to determine price elasticity for a selection of commercial and industrial general service customers, but was unable to**

**detect a price response. This suggests that these customers may not have responded to price changes for the period analyzed, which was 2010 and 2011. This analysis was documented in the Evaluation of the Large and Medium General Service Rates for F2014, which was filed as evidence for our 2015 Rate Design Application.**

**The studies summarized above demonstrate that price elasticity of demand has been modest in B.C.**

**<u>Limitations of Adopting Elasticity from Other Regions and Subtracting DSM</u>**

**BC Hydro does not agree with the approach suggested by some participants in the Inquiry to:**

**i. Arbitrarily increase the price elasticity used to reduce the forecast load based on an estimate from another jurisdiction and then,**

**ii. Further subtract BC Hydro's original estimate of DSM savings from forecast load.**

**With respect to the suggestion in (i) that we should use a price elasticity estimate based on other jurisdictional evidence, BC Hydro notes that price elasticity varies by region based on variables such as electricity price levels, price and availability of fuel substitutes, electricity end uses, etc. In addition, industry studies on price elasticity vary to the extent that they have or are able to control for all of the variables that impact electricity consumption, including DSM. If studies for other regions are not reflective of BC Hydro's customer environment, and do not control for variables, such as DSM, that influence BC Hydro customer electricity consumption, their results should not be applied to B.C.**

**BC Hydro has not seen any analysis provided in this inquiry that indicates the elasticity values suggested in other studies are applicable to B.C. Furthermore, jurisdictional information has minimal use when a utility has done its own studies on elasticity as done by BC Hydro.**

**With respect to the notion in (ii) that DSM savings can then be further subtracted from the forecast load after the elasticity impacts based on other jurisdictional evidence has been used to reduce forecast load, this is also flawed. As mentioned above, not all studies on elasticity have or are able to control for DSM. Subtracting DSM savings in addition to the reduction attributed to an assumed higher price response is expected to result in overestimating what the combined reduction in electricity consumption would be.**

**For example, as noted above, BC Hydro completed an empirical study of price elasticity of demand for our industrial customers, using data from 2002 to 2009. The customers included in the analysis were participants in various DSM programs and achieved DSM savings over the period analyzed. In this study, we**

**found that excluding DSM from the analysis artificially increased the magnitude of price elasticity from -0.16 to -0.21. This example illustrates that an empirical study that does not control for DSM effects can overstate price response.**

**Put differently, some jurisdictional studies on elasticities may be better compared to an implied elasticity response that is inclusive of DSM. BC Hydro provided this calculation to the Joint Review Panel conducting the Environmental Assessment of Site C. At that time, BC Hydro estimated an overall effective price elasticity in our December 2012 net Load Forecast (including estimated rate impacts and DSM savings) to be -0.57 for F2033. This is a more appropriate comparison to the empirical elasticity values in studies that did not control for DSM.**

**<u>Approach to Updating Load Forecast Should Price Elasticity Change</u>**

**If it was assumed that the price elasticity had a greater magnitude than BC Hydro's own estimates, BC Hydro would need to consider:**

- **what customer actions would be taken in response to future rate increases; and**
- **how that overlaps with planned DSM savings.**

**Increased magnitude of price elasticity could result in the need for BC Hydro to redesign its DSM programs in light of the updated customer response and to update our DSM program savings forecast to reflect potentially higher free ridership levels. Free ridership refers to the concept that some DSM program participants would have undertaken the energy savings actions even in the absence of the DSM program. BC Hydro adjusts DSM program savings for free ridership. Higher levels of free ridership could occur if customers became more price responsive (i.e., willing to act in response to the price increase alone and without the need for DSM initiatives to help further overcome remaining barriers). Higher levels of free ridership would result in less net DSM program savings.**

**To the extent that DSM was solely motivated by price and not other market factors, one possible outcome is that the combined load reduction (DSM + price response) would not change, but the allocation between DSM and price elasticity (i.e., response to price increase alone) may change.**

**<u>Summary</u>**

**In summary, BC Hydro believes that its current approach to accounting for the effects of elasticity and DSM is appropriate. Empirical evidence provides support for BC Hydro's assumptions on elasticity. As BC Hydro's elasticity estimate controls for DSM, it is then appropriate to subtract DSM savings.**

- ***Please confirm, or explain otherwise, that BC Hydro has assumed zero***

***real rate increases as part of its load forecast beyond 2024 (i.e. beyond the 2013 10 Year Rates Plan) and that any rate increases introduced between F2025 and F2036 would lower the Current Load Forecast. If confirmed, please explain the basis for and the reasonableness of this assumption.***

**The first part of the question is confirmed. BC Hydro has assumed annual rate increases of 2.0 per cent nominal beyond F2024. Based on forecast inflation of 2.0 per cent, these rate increases are zero in real terms.**

**The second part of the question is not confirmed. More specifically, it is not confirmed that "any rate increases introduced between fiscal 2025 and fiscal 2036 would lower the Current Load Forecast." Any annual real rate increases or decreases over the F2025 to F2036 period could alter the Current Load Forecast.**

**Please refer to BC Hydro's response to BCUC IR 2.51.0 for information on why BC Hydro considers that its assumption of no real rate increases over the very long term is not unreasonable. As shown in that answer, this assumption reflects BC Hydro's actual historical increases in residential rates.**

**Also as noted in that response, Government and BC Hydro have shown that they have taken actions to keep rates among the lowest in North America, including recent actions taken to do so despite lower forecast revenues of over $3.5 billion. While there are many risks over the very long term impacting the ability to keep rates low, BC Hydro considers that actions will be taken to do so. It is not possible to provide a detailed explanation of the risks that may occur over the next 70 years.**

- ***Please provide a detailed explanation of the risks which might prevent BC Hydro from achieving its projected zero real rate increases.***

**BC Hydro has not "projected zero real rate increases" as suggested in the question. In Appendix R of the August 30 Filing, we note that we have used our "…total projected revenue requirement…" based on "…assumed future rate increases" (emphasis added). We then further explain that we have "…assumed for the purposes of this analysis annual rate increases equal to inflation of 2.0 per cent" (emphasis added).**

**With respect to the risks regarding our assumed zero real rate increases beyond F2024, please refer to the response to BCUC IR 2.51.0, summarized above.**

- ***The Panel also invites submissions from other parties to assist the Panel in assessing the appropriateness of the assumptions related to price elasticity and future rate increases.***

**Section 5.3.3 of The Deloitte Report No. 2, regarding Alternative Resource Options and Load Forecast Assessment refers to several papers describing research from regions outside British Columbia to suggest alternative price elasticity assumptions. BC Hydro disagrees with adopting price elasticity estimates from studies conducted in regions dissimilar to British Columbia for the reasons described above.**

**BC Hydro periodically evaluates the price elasticity of its customers and is currently conducting an internal price elasticity study for the residential sector.**[1]

**Deloitte further suggests it may be an oversimplification to assume constant price elasticity of demand across all customer segments. BC Hydro agrees with this suggestion, and our own empirical research (described above) also suggests price elasticity of demand varies by sector, with large industrial customers being the most price responsive; commercial and light industrial customers being the least price responsive. BC Hydro addresses this issue as follows:**

- **Our empirical research indicates that historically, price elasticity for residential customers has been between 0 and -0.13. We have adopted an elasticity of -0.05 as a reasonable estimate supported by this evidence.**

- **Our empirical research indicates that historically price elasticity for commercial and light industrial customers may have been close to zero. To be conservative, we have adopted -0.05 for planning purposes.**

- **Our empirical research indicates that historically, large industrial customers have been more price sensitive than other customer segments. BC Hydro adopts a bottom up, industrial sector forecast to account for the possible effects of changes to the business environment including prices. In addition to the bottom-up estimates, BC Hydro applies a -0.05 price elasticity for planning purposes.**

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[1] **The GDS Audit Report recommended completing this internal price elasticity study.**

**21.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 68**

2.21.0 BC Hydro is asked to confirm that there are no other planned resources that have been excluded from these tables. Although energy and capacity from existing and committed Heritage resources are the subject of government approved integrated resource plans, it would be informative if BC Hydro would comment on Dr.
Ruskin′s submission and further explain how BC Hydro determined how much energy and capacity are available from existing and committed Heritage resources.

**RESPONSE:**

**BC Hydro's response to this information request is organized as follows: (A) Planned Resources in the Load Resource Balance; (B) Comments on Dr. Ruskin's Submission; and (3) Description of BC Hydro's Assessment of Energy and Capacity Capability.**

**(A) <u>Planned Resources in the Load Resource Balance</u>**

**BC Hydro confirms that other than Revelstoke Unit 6 and Site C there are no other currently planned resources[1] that have not been included in the tables provided in Appendix K of BC Hydro's August 30 Filing or in the subsequently updated Appendix K tables provided in BC Hydro's response to BCUC IR 1.4.0.**

**(B) <u>Comments on Dr. Ruskin's Submission</u>**

**Dr. Ruskin's submission identifies the following three key themes with respect to system reliability and alternatives that have already been addressed in our analysis and are explained further below:**

1. **<u>Planning Reliance on Existing and Committed Heritage Resources</u>: BC Hydro should use the average energy capability over time for our Heritage hydroelectric facilities to capture the diversity offered by multi-year storage and different river systems that can have complementary inflow profiles thereby increasing total system capability.**

2. **<u>Planning Reserve Requirements</u>: BC Hydro should reduce our generation planning reserve requirements because transmission outages present a greater risk for system reliability.**

[1] **BC Hydro notes on page 59 of our August 30 Filing that our recent acquisition of Waneta generating facility does not have an impact to BC Hydro's load resource balance because it is offset by Teck smelter load.**

3. **<u>Alternatives to Site C</u>: BC Hydro should examine other alternatives such as adding capability at existing facilities, building new large hydroelectric projects; and relying on market electricity or the Canadian Entitlement to the downstream benefits.**

**In response to the first key theme on Heritage system reliability, BC Hydro already uses the approach suggested by Dr. Ruskin. The *Clean Energy Act* and BC Hydro's generation energy and generation capacity reliability planning criteria set the framework for assessing our system capability over the year and during winter peak demand. Our assessment of long term system energy capability considers average water conditions over a 70-year inflow record and includes a comprehensive model to simulate our system's multi-year storage capability. Our assessment of winter peak system capability calculates how much resources can contribute to meeting peak loads over specific typical durations of peak demand with a high level of confidence (85 per cent) and in consideration of resource availability, inflows, storage capability (if applicable), and resource characteristics and constraints.**

**In response to the second key theme, our loss of load analysis demonstrates that a 14 per cent planning reserve requirement is necessary to maintain system generation adequacy, by taking into account scheduled and reasonably expected unscheduled outages of system elements. Conversely, spinning reserve requirements, that BC Hydro must meet, are set by NERC and the Western Electricity Co-ordinating Council to make sure that there are resources that are available in real time to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements – these are different than the generation adequacy planning reserves. For more details on electric reliability please refer to "Information Sheet #3: Planning Criteria"[2] prepared for BC Hydro's Integrated Electricity Planning Committee Meeting #2 in February 2005. Additional details of our assessment of energy capability and dependable capacity capability are described below.**

**For the third key theme on alternatives, some of the options presented by Dr. Ruskin are not cost-effective alternatives to Site C, while others are not available because they have either been included in our plans already or they are prohibited by legislation. Table 1 below provides our comments for the resources identified by Dr. Ruskin.**

[2] https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/info_iep_pre_reading_3_meeting_2.pdf.

**Table 1 Resource Alternatives Identified by Dr. Ruskin**

| General Rationale for Exclusion | Resources and Additional Comments |
|---|---|
| **Prohibited by Legislation** | - **U.S. Imports and Downstream Benefits: Additional market reliance through inexpensive surplus generation in the U.S. (particularly in the freshet) or access to the Canadian Entitlement to the Downstream Benefits has been excluded from the analysis due to the *Clean Energy Act* requirement to be self-sufficient; our current high reliance on markets in below average water conditions; transmission constraints in the Pacific Northwest (including during the freshet period); and the long term uncertainty of Canadian Entitlement benefits. These reasons are more fully described in section 6.3.3 of Appendix L.**<br>- **New Large Hydroelectric Resources: The following 11 projects are identified in Schedule 2 of the *Clean Energy Act* as prohibited projects:**<br>**a) Murphy Creek;**<br>**b) Border;**<br>**c) High Site E;**<br>**d) Low Site E;**<br>**e) Elaho;**<br>**f) McGregor Lower Canyon;**<br>**g) Homathko River;**<br>**h) Liard River;**<br>**i) Iskut River;**<br>**j) Cutoff Mountain;**<br>**k) McGregor River Diversion** |
| **Already Existing, Committed or Planned** | - **Mica Unit 5: In operation**<br>- **Mica Unit 6: In operation**<br>- **Waneta Expansion Project: In operation**<br>- **Revelstoke Unit 6: Planned**<br>- **Site C: Planned** |

| General Rationale for Exclusion | Resources and Additional Comments |
|---|---|
| **Not Cost-Effective to Current Alternatives**<br>***As a result, the inclusion of these resources would not alter BC Hydro's conclusions reached in its August 30 Filing*** | - **<u>Keenleyside Additional Generation</u>: Although BC Hydro does not own Keenleyside generation, we believe that any incremental energy and capacity gains would not be more cost effective than current alternatives, as follows:**<br>  ○ **Additional generation capacity at Keenleyside may increase its dependable capacity and reduce some spill thereby increasing its energy capability;**<br>  ○ **However, not all spills can be prevented because there are times when the reservoir is too low to use the generation and we are required to release water downstream to comply with the Columbia River Treaty;[3] and**<br>  ○ **Further, the Columbia River treaty flows are agreed to on a weekly basis, so there aren't opportunities to adjust generation at shorter time intervals for load following as Site C can.**<br>- **<u>Duncan New Generation:</u> BC Hydro previously considered the option to add 30 MW of installed generation capacity at Duncan Dam, providing about 103 GWh/year. At a plant gate cost of approximately $98/MWh ($F2018) it would not alter BC Hydro's conclusions reached in our August 30 Filing.** |

**(C) <u>Description of BC Hydro's Assessment of Energy and Capacity Capability</u>**

**As a predominantly hydroelectric system with fluctuating inflows, BC Hydro needs to evaluate its resources' capability to ensure it can meet the sustained year-over-year energy demand while meeting its annual peak. We periodically conduct assessments of system resource energy and capacity capability reflecting current or planned upgrade conditions for all heritage assets aggregated with all existing and committed IPPs and other contractual arrangements that BC Hydro can depend on.**

**The following descriptions provide additional details on our determination of energy and capacity capability from existing and committed Heritage resources. In general our methodology for determining these values is consistent for both Heritage resources and resources owned by IPPs, with exceptions as noted for resources that have variable generation such as small run of river hydro, solar and wind. For additional details please also refer to section 8 of Appendix L and Appendix 3C from the 2013 Integrated Resource Plan[4].**

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[3] **The 1964 Columbia River Treaty is an international agreement between Canada and the U.S. for the cooperative development and operation of water resources in the Columbia River basin. The Treaty has provided substantial flood control and power generation benefits to both countries.**

[4] **https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300c-nov-2013-irp-appx-3c.pdf.**

**1) <u>Energy Capability</u>**

**The following descriptions outline our methodology for calculating our average and low water (also called Firm Energy Load Carrying Capability) energy capability. Calculating both metrics allows us to also understand our potential market reliance in below average water conditions.**

- **<u>Average Energy Capability</u>: To implement the Clean Energy Act self-sufficiency requirement, where the Heritage hydroelectric planning reliance must be based upon average water conditions, BC Hydro conducts Long Term System Capability studies. The studies reflect the characteristics and constraints of the current and planned BC Hydro system, allowing for imports in dry conditions and exports in wet conditions, to determine the average annual energy capability of the system under the various water conditions contained in our available historic period of record, presently from 1940 to 2010. The average annual generation from each resource over this 70-year period is defined as its average energy capability and is used in our Load Resource Balance. The average capability of BC Hydro's Heritage resources, excluding Revelstoke Unit 6 and Site C is about 48,500 GWh/year.**

- **<u>Firm Energy Load Carrying Capability</u>: The system capability during a period of extended multi-year drought (also called 'critical water conditions') is determined by modelling the current and planned system resources over the critical period[5], while augmenting natural streamflows by emptying all active storage (from full), to meet annual load with no reliance on market imports. The maximum annual load that requires all active storage and natural stream flows to be used is the system firm energy load carrying capability, currently estimated at about 44,400 GWh/year.**

**The difference between the Heritage hydro average energy capability and firm energy load carrying capability is approximately 4,100 GWh/year, which is the average non-firm energy capability of the Heritage hydro resources. Relying on this 4,100 GWh/year under average water conditions means that, on an operational basis, if Heritage hydro water conditions are lower than average, IPP non-firm energy and market purchases may be required to replace non-firm Heritage hydro.**

**2) <u>Capacity Capability</u>**

**For capacity capability we use two terms to define resource capability: dependable capacity and effective load carrying capability. The difference between the calculation methodologies for these two metrics is described below. For convenience, although dependable capacity is typically only used to describe the capacity contributions of non-variable resources, such as thermal and large hydroelectric resources, the capacity contributions of all resources are typically referred to as dependable capacity.**

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[5] **BC Hydro's critical water condition period is currently defined as the period of 1942 to 1946.**

- **<u>Dependable Capacity</u>: BC Hydro uses dependable capacity to assess the resource capability for the Heritage resources during winter peak load. This is the capacity that a plant can reliably deliver for the duration of time it is required, typically for three, eight, or 15 hours in the peak load period of weekdays during a continuous two weeks of cold winter. We define it differently depending on the level of upstream storage that can be controlled by BC Hydro, as follows:**

    - **<u>For plants with significant BC Hydro controllable upstream storage</u>: dependable capacity is calculated based on an 85 per cent confidence level of winter reservoir elevation after a consideration of operating constraints that may reduce the output (e.g., Peace Ice control flows).**

    - **<u>For other hydro plants</u>: dependable capacity is calculated for various durations (three, eight, or 15 hours) using an energy/capacity trade-off model and assuming typical winter starting reservoir elevation levels and 85 per cent confidence level of local inflows.**

- **<u>Effective Load Carrying Capability</u>: is the maximum peak load that a generating unit or system of units can reliably supply such that the Loss of Load Expectation will be no greater than one day in ten years. The capability of variable or intermittent resources rely on being aggregated with the system as a whole and can be impacted by fuel supply, planned outages, and forced outages due to mechanical failures.**

**All of the metrics described above are used in developing the energy and capacity Load/Resource Balances (LRBs) to determine future system needs.**

**23.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 76**

2.23.0 We have made the following assumptions with regard to additional terms in the question posed above:

1. *Commercially feasible* means full-scale technology demonstrated in an industrial (i.e. not R&D) environment for a defined period of time. Publicly verifiable data exists on technical and financial performance. Regulatory challenges (e.g. safety certifications, lack of standards) have been addressed in multiple jurisdictions.
2. *Grid reliability* means that Site C and alternative portfolios should include any network costs required to maintain BC Hydro's grid reliability standards.
3. *Maintenance* or *reduction* of 2016/2017 greenhouse gas emission levels means that the alternative portfolio must not increase the greenhouse gas intensity of BC Hydro's greenhouse gas emissions, as measured in CO2 tonnes equivalent per GWh generated

The Panel invites comment on the interpretations above.

**RESPONSE:**

1. ***Commercially feasible***

**BC Hydro generally agrees with the Commission's interpretation on "commercially feasible", however, consideration of resource viability should be added to the definition as follows:**

**Publicly verifiable data exists that confirms the viability of the resource in terms of its energy source (e.g. the availability of adequate volumes of hot water should be confirmed prior to a geothermal site being described as commercially available).**

**Resources like geothermal that have no verified energy source in B.C. are not viable and should not be relied upon.**

2. ***Grid reliability***

**BC Hydro's interpretation of "grid reliability" in this context refers to the reliability of an integrated power system grid consisting of generation, transmission and distribution. Cost and reliability of the integrated grid needs to be considered in portfolio analysis. BC Hydro follows Commission-approved Mandatory Reliability Standards to ensure adequate transmission system. Generation resources are**

**planned to meet the "one day in ten years Loss of Load Expectation" criterion, which is widely used by electric utility resource planning.**

3. ***Maintenance* or *reduction* of 2016/2017 greenhouse gas emission levels**

**Please refer to the response to BCUC IR 2.70.0 for BC Hydro's interpretation of Order-in-Council No. 244 Terms of Reference wording "maintenance or reduction of 2016/17 greenhouse gas emission levels".**

**33.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92**

2.33.0 The firm energy, columns F and G, are based on calculations which use these monthly energy profiles along with the project capacities, the source for which is undocumented. BC Hydro is requested to provide this data.

**RESPONSE:**

**The average annual energy shown in Column F ("Resource Options" tab in "AdjUEC (BCUC Request)") is based on the 2009 BC Hydro Wind Data Study and the 2009 BC Hydro Wind Data Study Update. The wind study was undertaken to identify the top potential wind projects in the province including determining the installed capacity in MW. In 2015, BC Hydro updated the average annual energy for the sites by applying updated turbine characteristics (such as 3 MW turbine size at 100 m hub height and updated generic power curves for each IEC turbine class) and loss assumptions, extended project life from 20 years to 25 years, but left the project total MW unchanged. The result of the update was increased energy generation potential for the same sites and lowering of unit energy costs.**

**The firm energy shown in Column G for these wind resources equals the corresponding average annual energy. We determined the firm energy load carrying capability (FELCC) for wind by utilizing ten years of monthly wind power production data for 95 potential wind generation plants across B.C., as identified in the 2009 BC Hydro Wind Data Study. Our analysis showed that the annual energy from wind resources is relatively stable from year to year over a variety of assumptions (both in terms of different aggregated volumes and different regional mix of resources). As such, we assumed that the average annual energy from wind resources can be treated as firm.**

**34.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92**

2.34.0 A "soft cost adjustment" of 1.025 is applied. BC Hydro is requested to explain how and why it selected this soft cost number?
BC Hydro is requested to provide this data.BC Hydro is requested to explain how and why it selected this soft cost number.

**RESPONSE:**

**The soft cost adjustment covers the costs associated with community and aboriginal accommodation (e.g., assessment, engagement/consultation and mitigation) for project developments. For most resources, these costs are already embedded in the capital cost estimate.**

**However, for onshore wind, the community/aboriginal accommodation costs are not captured in the capital cost estimates, but are instead included in the form of a soft cost adjustment. A range of 2 to 3 per cent of revenue was deemed as a reasonable estimate by external stakeholders during our 2015 resource options update engagement process (refer to the linked Meeting Notes for May 5, 2015 BC Hydro Wind Resource Engagement).**

**35.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92**

2.35.0 BC Hydro is requested to explain why it used $50.36 per MWh for a Mid C price and why it used these values for super peak, peak and off-peak.

**RESPONSE:**

**The $50.36/MWh (2015 real CAD) is a 40 year levelized price based on the ABB Spring 2016 Base Case Mid-C market electricity price forecast, the same forecast as provided in the F2017-F2019 RRA filing and for BC Hydro's Site C Review August 30 Filing. The 40-year levelized value was chosen to be consistent with the longest contract for which we have signed Electricity Purchase Agreements.**

**The $50.36 per MWh Mid-C (annual) price was used to value non-firm energy that comes from some resource options based upon the varying energy delivery profiles over the year. When this market price is multiplied by the 3 x 12 Time of Delivery price adjustments (described in BC Hydro's response to BCUC IR 2.26.0) it yields the set of prices for the three different time periods (super peak, peak and off-peak) for each of the 12 months of the year.**

**Although this market price and 3 x 12 table were in the spreadsheet that was used (it is a standard template), the market price and 3 x 12 table were not applied in the portfolio analysis included in the August 30 Filing. Since wind projects do not have non-firm energy (average annual output is used since there is little year to year variability), the Mid-C price of $50.36 per MWh has no effect on the adjusted UEC. It doesn't effect Site C's adjusted UEC either because Site C's average annual energy is similarly used for planning.**

**37.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92**

2.37.0 Wind integration and network upgrade are both upward adders. However, in contrast to the unexplained inputs and formulas for CIFT and line losses, the wind integration and network upgrade adders appear simply as numbers in this spreadsheet. BC Hydro is requested to explain in more detail the basis for selecting the amounts for these adders.

**RESPONSE:**

**Wind Integration Cost**

**In 2010, BC Hydro conducted a Wind Integration Study which looked at the cost of integrating wind power onto the electric system across various study scenarios. Based on this study, a wind integration cost of $10/MWh was used in the 2013 IRP. An update to the 2010 study has not been completed, but BC Hydro recognizes that a number of factors that would impact the integration cost, such as reduced natural gas prices and market conditions. In advance of completing the updated study, BC Hydro used a wind integration cost of $5/MWh in its August 30 Filing to the Commission. The $5/MWh wind integration cost estimate is in line with a recent survey of wind integration studies by the US Department of Energy (2016 Wind Technologies Market Report).**

**Network Upgrade (NU) Adder**

**The NU adder reflects the cost of network upgrades required to interconnect the resource options to the bulk transmission system that are borne by BC Hydro. The $6/MWh NU adder used was the weighted average of NU cost from the Clean Power Call results (2010). NU costs were provided in the interconnection studies conducted for each project in the Clean Power Call.**

**43.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 93**

2.43.0 BC Hydro is requested to comment on CEABC's submission that the wind integration charge "is an allowance to compensate for a possible lost opportunity to sell capacity in the day forward market".

**RESPONSE:**

**The wind integration cost consists of two components: 1) incremental operating reserves cost associated with wind power generation; and 2) day-ahead (DA) power trading opportunity cost. Operating reserves are generating capacity resources that are reserved to manage the electric system on a daily basis. These operating reserves are over and above contingency reserves which are held to address unplanned system outage events. The DA power trading opportunity cost captures the impact of wind forecast uncertainty on the power trading activities in the DA timeframe.**

**The Wind Integration Study models how BC Hydro, through its power trading subsidiary, Powerex, participates in the DA power trading market. Powerex typically enters a position in the DA market that fully utilizes the DA planned system storage or excess generation, but for which Powerex also has a high degree of certainty that it can deliver as there are penalties associated with non-delivery and reputation risks that are too punitive for Powerex to be exposed to. With wind power generation output being uncertain in the DA timeframe, a portion of the BC Hydro system flexibility has to be withheld from the market in order to manage system operating requirements. It is these foregone trade impacts that are also being captured in the DA power trading opportunity cost.**

**In this study, DA wind opportunity costs are not incurred to the extent that the transmission interties are constrained as there would otherwise not have been an opportunity to use the reserved hydro flexibility.**

**51.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 104**

2.51.0 Given the future incremental portfolio after the successful completion of Site C, how valid is the assumption of no real rate increases given the cost of the incremental additions? BC Hydro is requested to respond to this question.

**RESPONSE:**

**As stated in Appendix R, BC Hydro is assuming annual rate increases equal to inflation of 2.0 per cent for all year subsequent to fiscal 2024. As noted in the Commission's Preliminary Report, and as noted in BC Hydro's response to AMPC IR 1.1.10 in the proceeding related to the F2017 - F2019 Revenue Requirements Application, "current forecasts do not extend past fiscal 2024 and BC Hydro is thus unable to perform the requested calculation".**

**While BC Hydro expects new alternative resources to create upward pressure on ratepayer costs, there is a downward impact on ratepayer costs provided by BC Hydro's existing and future heritage assets. The cost of large hydroelectric facilities declines over time as capital investment is paid off and financing costs reduced. This effect continues with respect to BC Hydro's existing heritage assets, and will happen in the future with Site C. The net effect of these upward and downward effects will depend on factors such as the actual costs of alternative resources and the required capital investments in BC Hydro facilities.**

**Further to the above, Governments, past and present, and BC Hydro have taken actions to keep electricity rates among the lowest in North America. We expect this to remain unchanged over the long term. Recently, both Government and BC Hydro have taken actions to keep rates low, including those related to the 2011 Government Review, the 2013 10 Year Rates Plan, and subsequent actions to remain on track with the 2013 10 Year Rates Plan. These actions are detailed in section 1.4 of the F2017 - F2019 Revenue Requirements Application, and in a number of responses to RRA information requests, including BC Hydro's response to CEA IR 1.3.2. As noted in section 1.1 of the F2017 - F2019 Revenue Requirements Application, actions taken include those to mitigate lower forecast revenues of $3.5 billion.**

**If the cost of incremental additional energy sources in future revenue requirements resulted in cost pressures, we anticipate that BC Hydro would take actions, which may include working with Government, to keep rates low and affordable over the long term.**

**Over the long-term, BC Hydro's residential rates have not increased on a real basis. In 1967 (50 years ago), the monthly BC Hydro residential bill for typical**

**consumption of 1,000 kwh/month was $15.50. Using the Bank of Canada inflation calculator (see http://www.bankofcanada.ca/rates/related/inflation-calculator/), this would represent $110.53 in 2017 dollars. Today, based on consumption of 1,000 kwh / month, a BC Hydro customer will pay $110.81 (including the rate rider). Therefore, over the long term, customer residential bills have remained unchanged, on a real basis. BC Hydro also has data going back a few more years which shows that residential rates have decreased, on a real basis, if that data is considered.**

**Although future increases in customer rates will not be based on past increases in rates, this historical pattern indicates that, over the very long term, it is not unreasonable to assume that BC Hydro rates will not increase on a real basis.**

**61.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-11**

2.61.0 The Panel therefore asks BC Hydro and other parties to respond to the following questions:

- How much has BC Hydro spent in the last 15 years in exploratory drilling for geothermal resources?
    - Please explain whether there has been (or is expected to be) a significant reduction in drilling costs compared to those assumed in the 2015 Geoscience BC Report, and how this could affect both the probability of locating economic reserves by 2025/2035 and/or the cost of those reserves.
    - If BC Hydro were to accelerate the development of the geothermal industry in BC by undertaking additional exploratory drilling, please estimate the size of the budget that would reasonably be required.
- Please provide an update of the $81/MWh ($2018) estimated cost of the two geothermal projects identified by BC Hydro (about 1300 GWh and 200 MW total) delivered to the Lower Mainland, using BC Hydro's cost of financing and current operational costs. Please provide all input assumptions used to calculate the estimated cost, and supporting calculations.
- Do the capital costs as provided by the Canadian Geothermal Association also include exploration costs?

Please estimate the probability that, by (i) by 2025, and (ii) by 2035, BC Hydro would reasonably be able to locate 200 MW of cost-effective geothermal energy if BC Hydro were to develop the resource in partnership with industry.

**RESPONSE:**

**<u>Geothermal Resources</u>**

**The amount of geothermal resources proposed in the Deloitte report is more than the total geothermal generation in the country of Iceland, and would be developed over an implausible time period. BC Hydro provides information on global geothermal development over the past 50 years as context for an assessment of the viability of the resource in B.C.**

**<u>Iceland</u>**

**While B.C. and Canada have no experience in utility-scale geothermal electricity facilities, there are a number of areas in the world that have pursued geothermal. In**

**particular, the Commission references Iceland as one example on page 10 of Appendix A in its Preliminary Report. Iceland can be characterized as an outstanding geothermal location that has used a lot of geothermal for heating and has started to develop its geothermal electricity resources.**

**Iceland is an unusual geological formation, being one of the few locations on the earth where the deep mantle material between two tectonic plates rises up above sea level.[1] The heat flow through the earth's crust in Iceland is several times the world average.[2] This suggests that Iceland is probably one of the best locations in the world to find geothermal energy potential.**

**The majority of the geothermal development in Iceland over the first half of the last century was in low grade heat for housing while the last few decades had Iceland focusing on high temperature steam electricity production.[3] The direct usage of geothermal energy is very prevalent in Iceland with nine of ten homes supplied from geothermal heat sources.[4] However, Iceland current only draws about 25 per cent of its electricity (665 MW) from geothermal energy with greater than 70 per cent coming from hydro resources.[5]**

**The review and development of Iceland's high temperature geothermal has been under investigation since the 1970s starting with exploration and drilling discovery programs for power plant construction in a single phase. However, since the early 2000's, this has moved to a stepwise development with fields developed in many stages. Current thinking in Iceland suggests that a broad assessment of potential geothermal sites be undertaken through reconnaissance, geological, geochemical and geophysical studies before drilling is undertaken can be a more conservative lower cost development strategy.[6]**

**Iceland has 665 MW of installed geothermal electricity after decades of development. This suggests that geothermal electricity development is still a difficult and risky undertaking but the usage of geothermal heat for heating where communities are close to geothermal resources is less risky and more profitable. It would appear that Iceland is still refining their geothermal electricity development capabilities and that they are still looking to de-risk development.**

**<u>U.S. and Global</u>**

**Geothermal development in other parts of the world is undergoing slow careful development, with growth seen primarily in expansion projects at sites with a proven geothermal resource. In 2015, 313 MW of additional geothermal capacity was added**

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1 **http://www.nea.is/geothermal/the-resource/.**
2 **http://www.os.is/gogn/unu-gtp-sc/UNU-GTP-SC-18-32.pdf.**
3 **Ibid.**
4 **http://www.nea.is/geothermal/direct-utilization/.**
5 http://px.hagstofa.is/pxen/pxweb/en/Atvinnuvegir/Atvinnuvegir__orkumal/IDN02101.px/table/tableViewLayout1/?rxid=87437289-5a42-43a6-a5b3-6a4d868b8d30.
6 **http://www.os.is/gogn/unu-gtp-sc/UNU-GTP-SC-18-32.pdf.**

**globally, a growth of 2.4 per cent. This modest growth is despite a global pipeline of more than 12.5 GW of identified geothermal projects at some early or advanced stage of development.[7] The slow growth of geothermal despite broad global efforts to bring new projects to market appears to be a reflection of barriers to project development related to permitting, finance, and resource uncertainty that together lead to long project development timelines and high rates of project cancellation. Even in the U.S. – with an established geothermal industry and with many geothermal reservoirs fully explored and de-risked – only 77 MW of geothermal at two expansion sites were brought online in 2015. This is despite a geothermal project pipeline in the U.S. of 6.4 GW by 2015.[8] This suggests that steady growth of successful geothermal projects must be supported by broad-based efforts to advance a wide portfolio of potential geothermal projects, most of which are sure to be cancelled or postponed.**

**In comparison to a global geothermal pipeline of 12.5 GW or a U.S. geothermal pipeline of 6.4 GW, B.C. has a nearly empty cupboard. Projects within the pipeline can be at one of five stages, ranging from Prospect (defined as areas in which little exploration has taken place and the country's government has tendered the property to a private company, government agency or contractor to conduct further exploration) to Phase IV (Resource Production and Power Plant Construction). Of the B.C. geothermal projects known to BC Hydro at this time, only one has reached Phase II and it has been postponed indefinitely as the developer has announced no current intentions to develop the site (South Meager Creek), and only three more at Phase I representing ~45 MW. No other resources in B.C. can even be considered at the Prospect Stage.**

**Geothermal exploration in the U.S. began in earnest in 1960, focused on the California Geysers. It was not until 1980 – 20 years later – that geothermal reached 755 MW of installed geothermal capacity in the entire U.S. The California Geysers – a huge dry-steam reservoir that generated 2000 MW by 1988 – is the gold standard for geothermal power projects, and no similar field is thought to exist in B.C. Geothermal development in the U.S. since the fulsome development in the geysers has slowed, with the most recent addition of 1000 MW taking approximately 20 years to come on line.**

**<u>Geothermal Exploration In B.C.</u>**

**BC Hydro does not have a mandate to conduct exploration for geothermal energy resources. BC Hydro has not invested in exploratory geothermal drilling in the last 15 years, although investment was made prior to this timeframe based on Commission recommendations from the 1982 Site C review.**

**In 2015, BC Hydro spent approximately $100,000 to co-fund with GeoscienceBC a detailed study, "An Assessment of the Economic Viability of Selected Geothermal Resources in British Columbia." To develop the study, GeoscienceBC held an open call for proposals, and ultimately selected a team led by a consultancy with in-depth knowledge of the B.C. IPP and electricity sector environment (Kerr Wood Leidal), in**

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[7] **Geothermal Energy Association, "2016 Annual US and Global Geothermal Power Production Report".**

[8] **NREL, "Doubling Geothermal Generation Capacity by 2020: A Strategic Analysis".**

**partnership with a globally premiere consultancy specializing in all aspects of geothermal development and geothermal finance (Geothermex). GeoscienceBC created a Technical Advisory Committee populated by B.C.-based geothermal specialists to oversee the direction and quality of the work. The purpose of the study was to amalgamate all available data pertaining to B.C.-based geothermal resources and conduct an unbiased technical and economical assessment of these resources, using both global expertise and local experience to guide the work. Prior the study, BC Hydro spent $100,000 over two years to enable the work of a Geothermal Specialist at the Ministry of Energy to implement regulatory changes governing geothermal rights and tenure, as well as perform a detailed geothermal resource assessment for areas in the B.C. Northeast using data collected by the Ministry from the oil and gas sector.**

**From 1974 – 1984, BC Hydro managed a geothermal exploration program to characterize the geothermal resource in B.C., focused primarily in the area around Meager Mountain. This program was expensive and it was a failure. The ten-year effort involved extensive surveying, drilling and analysis, including dozens of shallow bore holes and three full-diameter production wells 3,000 m deep in an effort to confirm a viable geothermal resource at Meager Creek. However, no significant flow was observed from any of the three production wells, and exploration was discontinued. A summary of BC Hydro's geothermal work program at Meager Mountain is available in a 2012 report from the Geological Survey of Canada,[9] and BC Hydro's reports from all the regional investigations are available here: http://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/renewable-energy/geothermal-energy/geoscience.**

**Drilling Costs In B.C.**

**The cost of geothermal drilling is dependent on three primary variables: the depth of drilling, the geology, and the drill rig rental rate. The drill rig rental rate is itself dependant on the relative competition for equipment from the oil and gas sector. As oil and gas sector activity has seen boom and bust cycles, so has the drill rig rental rate applicable for geothermal activities. BC Hydro and GeoscienceBC requested the consultants of the above report to consider the impact on the cost of geothermal in B.C. from changing drilling costs over time. As per the above report:**

**"The potential exists at the current time for lower drilling costs as a result of the decline in oil prices over the past year or so. It is however not readily apparent that this trend will carry forward in the long term. Since this assessment has such a long-term perspective, it would not be prudent to base the results on what may be a short-term anomaly in oil prices and resulting drilling costs. Rather, a sensitivity analysis around drilling costs would provide further insight into the effect of drilling cost on the LCOEs."**

**The report included a sensitivity analysis for two of the lower cost potential geothermal sites, with the resultant LCOEs (equivalent to BC Hydro's UECs) shown below. The relationship between a lower or higher drilling cost and probabilities of locating a viable**

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[9] **Grasby et al (2012) "Geothermal Energy Resource Potential of Canada".**

**geothermal resource is difficult to quantify. It stands to reason that at lower drilling costs, one can afford a more conservative development approach whereby there are more exploratory drilling holes to learn more about the reservoir, and more confirmation wells can fail before abandoning a project, although the probability of whether a viable geothermal resource exists remains unchanged.**

Table 6-4: Sensitivity Analysis for Drilling Costs

| | LCOE (CAN ¢/kWh) | | |
|---|---|---|---|
| Project | Base Case | Drilling Costs at 50% of Base Case | Drilling Costs at 150% of Base Case |
| Pebble Creek | 11.5 | 7.8 | 15.2 |
| Sloquet Creek | 21.8 | 15.7 | 27.7 |

**<u>Potential for BC Hydro to Advance Geothermal Through Drilling</u>**

**If BC Hydro were to accelerate the development of the geothermal industry by drilling exploratory wells, we would likely undertake the first two stages of drilling – the exploratory and the confirmation stage drilling as described in the GeoScienceBC report – at a cost of approximately $683 million. This assumes the resources could be proven based upon the assumed number of wells shown in the report at the expected cost for drilling to confirm up to 310 MW of dependable capacity from the 11 most economically viable sites in B.C. This cost figure is presented as 'overnight capital cost', which assumes the money is spent without any associated inflation or cost of financing over the decade of exploration and confirmation activities.**

**In reality, private enterprises seeking to finance these high-risk exploration and confirmation activities would normally face financing costs between 15 to 30 per cent per year by virtue of the perceived risk. Further, exploration and confirmation at some of those sites are likely to fail to prove the resource, with some (and potentially most) of the 310 MW left undeveloped. If BC Hydro drilled an average of twice the number of holes the costs would be over $1 billion, again with no guarantee of successful wells.**

**<u>Updated BC Hydro Study Geothermal Costs</u>**

**BC Hydro provided an assessment of the potential costs of geothermal resources in section 6.2.7 of Appendix L to our August 30 Filing. BC Hydro's purpose of developing the low-cost case of geothermal resources, which reached as low as $81/MWh, was to acknowledge the uncertainty in all geothermal cost assessments and to define a lower-cost boundary where all major sources of cost uncertainty line up to produce the most optimistic outcome. For planning purposes, this low cost case is overly optimistic and unreasonable. The assumptions incorporated into the Kerr Wood Leidal assessment of costs are fulsomely described in their report and represent their expert view of reasonable costs in the B.C. context.**

**BC Hydro's assumptions underlying the low-cost case build upon the Kerr Wood Leidal assumptions relating to resource size and approach to development, but we have changed three of their primary cost assumption parameters into what we consider the most optimistic case. BC Hydro's changes are described in detail in the BC Hydro**

**Technical Supplement added to the Kerr Wood Leidal report found here: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-geothermal-technical-supplement-201610.pdf. In brief summary, the relevant input assumptions are:**

1. **Low Cost of Drilling. Drilling costs in B..C assumed to be consistent with low costs observed in the U.S. context. For comparison, the KWL report assumed an average drilling cost of ~$4,000/meter for full-scale production wells, while the low cost case assumed an average drilling cost of ~$2,300/meter for full-scale production wells. Cost reductions of a similar scale are assumed for exploration and confirmation wells;**

2. **High Success of Drilling. Extremely optimistic drilling outcomes are assumed in both the confirmation drilling and production field development phases. For comparison, the KWL report assumed a 60 per cent and 80 per cent success rate in the two phases respectively, while the low cost case assumed a 90 per cent success rates in each phase. As an example, the low cost case has four fewer 'dry wells' in the Pebble Creek project that are not usable as injection wells relative to the KWL report; and**

3. **Low cost of financing. A flat 5 per cent cost of capital was applied to all stages of project development. For comparison, the KWL report applied a variable cost of capital to the costs of different stages of development, ranging from 7 per cent to 30 per cent consistent with the perceived risk of the investment, applicable for the duration of project development.**

**CANGEA Cost Estimate**

**The details of the Canadian Geothermal Association's estimate of capital costs are not included in their submission, however it would appear that their estimate of capital costs is based on a 2012 report from the Energy Sector Management Assistance Program (ESMAP).[10] The report includes a table of indicative costs for geothermal development reproduced below, which includes an estimate of exploration costs ranging from $2 to $4 million. It should be noted that ESMAP's mission is to provide analysis suitable for low- and middle-income countries, and their indicative costs may not be suitable for application to the B.C. context.**

[10] **ESMAP (2012) "Geothermal Handbook: Planning and Financing Power Generation."**

**TABLE 1.6**

Indicative Costs for Geothermal Development (50 MW ex generator capacity), in US$ Millions

| PHASE / ACTIVITY | | LOW ESTIMATE | MEDIUM ESTIMATE | HIGH ESTIMATE |
|---|---|---|---|---|
| 1 | Preliminary Survey, Permits, Market Analysis[16] | 1 | 2 | 5 |
| 2 | Exploration[17] | 2 | 3 | 4 |
| 3 | Test Drillings, Well Testing, Reservoir Evaluation[18] | 11 | 18 | 30 |
| 4 | Feasibility Study, Project Planning, Funding, Contracts, Insurances, etc.[19] | 5 | 7 | 10 |
| 5 | Drillings (20 boreholes)[20] | 45 | 70 | 100 |
| 6 | Construction (power plant, cooling, infrastructure, etc.)[21] | 65 | 75 | 95 |
| | Steam Gathering System and Substation, Connection to Grid (transmission)[22] | 10 | 16 | 22 |
| 7 | Start-up and Commissioning[23] | 3 | 5 | 8 |
| | **TOTAL** | **142** | **196** | **274** |
| | In US$ Million per MW Installed | 2.8 | 3.9 | 5.5 |

*Source | Authors.*

**These costs are substantially below the estimates of both BC Hydro (through our consultant Kerr Wood Leidal) and Deloitte in their submission. They are unlikely to be meaningful for geothermal development in B.C.**

**<u>Probability of Developing 200 MW of Cost Effective Geothermal By 2025 and 2035</u>**

**BC Hydro has no basis upon which to answer the Commission's request to estimate the probability of cost effective geothermal development by 2025 or 2035. In the KWL report, exploration or resource risk associated with all known potential geothermal sites was assessed in terms relevant to the geothermal industry. As seen from the report excerpt below, all known geothermal resources in B.C. are characterized as "high risk", with the exception of Meager Creek which is a "high-moderate risk" by virtue of the ten-years of BC Hydro exploration and additional $30 million of exploration carried out by the private sector at the same site without any success.**

**Given B.C.'s very preliminary state of geothermal resource characterization geothermal should not be included in an alternative resource portfolio in timeframe sufficient to be an alternative to Site C. Undertaking the detailed analysis required (using Iceland's staged resource assessment process as a model) to characterize geothermal would likely take five to ten years to explore all the sites and obtain history of geological data after which some more educated guesses on how to develop sites and approach the drilling could be made. As a result, expecting material amounts of geothermal electricity generation in B.C. by 2025 is unrealistic.**

**Table 3-3: Geothermal Resource Exploration Uncertainty**

| Geothermal Site | Development Phase | Project Risk | Cumulative Cost |
|---|---|---|---|
| Canoe Creek – Valemount | Exploration | High | <5% |
| Clarke Lake | Exploration | High | <5% |
| Clearwater Volcanic Field | Pre-Survey | High | 0% |
| Iskut | Pre-Survey | High | 0% |
| Jedney Area | Exploration | High | <5% |
| King Island | Pre-Survey | High | 0% |
| Kootenay | Pre-Survey | High | <5% |
| Lakelse Lake | Exploration | High | <5% |
| Lower Arrow Lake | Pre-Survey | High | 0% |
| Meager Creek | Test Drilling | High-Moderate | ~15% |
| Pebble Creek | Test Drilling | High | ~10% |
| Mt. Cayley | Exploration | High | <5% |
| Mt. Garibaldi | Pre-Survey | High | 0% |
| Mt. Silverthrone – Knight Inlet | Pre-Survey | High | 0% |
| Nazko Cone | Exploration | High | <5% |
| Okanagan | Exploration | High | <5% |
| Sloquet Hot Springs | Exploration | High | <5% |
| Sphaler Creek | Pre-Survey | High | 0% |
| Upper Arrow | Pre-Survey | High | 0% |

**69.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-31**

2.69.0 It is difficult to understand how purchasing backup capacity can be cheaper than dispatching from a facility with which it has a take or pay contract. BCF Hydro is requested to please explain under what circumstances Island Cogeneration has been dispatched in the past three years and how much energy has been purchased from the facility.

**RESPONSE:**

**BC Hydro has a planned reliance upon Island Generation (IG) for 2170 GWh of firm energy and 275 MW of dependable capacity.**

**The IG contract is a tolling contract and not a take or pay contract. BC Hydro pays a fixed demand charge to ensure that IG is available when required to support BC Hydro load. In dispatching IG, BC Hydro will purchase natural gas from the market and deliver it to the project to generate electricity. As a result, unlike other take or pay contracts like wind, solar or run-of-river, BC Hydro is not required to acquire the energy that this plant can generate but rather will only acquire it when it is needed.**

**There are two reasons that BC Hydro would not run IG to its full output. The first is to absorb high energy inflows from either the Heritage Hydro system or from IPPs in years with high water inflows. The second is as a result of the the provincial carbon tax. The carbon tax results in a cost of 11 $/MWh at the current value of the tax, and will increase as the tax increases. This frequently makes the plant non-competitive with other resources in the Pacific Northwest that do not face a similar tax. BC Hydro rarely makes use of IG's firm energy contribution, instead favouring cheaper electricity imports; however, it is a valuable insurance policy should BC Hydro face circumstances where energy supplies are limited.**

**BC Hydro does, however, make use of IG's ability to provide dependable capacity, and does so on an as-needed basis. BC Hydro will dispatch IG under the following circumstances:**

- **To support Vancouver Island reliability during periods of VI transmission line outages; and**
- **To serve high domestic loads during cold snaps.**

**It is during instances such as these (outages, cold snaps) that BC Hydro relies upon external markets for backup capacity supply to supplement the capacity provided by IG and BC Hydro's large hydro facilities.**

**There are many resources such as variable clean resources in BC Hydro's supply stack that are relatively new additions to our system. Market capacity backup is important as BC Hydro strives to gain a better understanding of the behaviour of such resources during the winter peak. As an example, wind resources are currently counted on to provide 26 per cent of their installed capacity as effective load carrying capability (ELCC) that could meet system winter peak load. This value is a theoretical value based on modelled wind data. Market capacity backup will ensure system reliability as BC Hydro experiences the output of newly constructed wind projects in the province and determines whether the actual output of the facilities during a prolonged cold snap validates theoretical estimates for ELCC. Market capacity in such instances is not an alternative to IG, which would likely be already operating to meet system peak demand.**

**BC Hydro notes that IG is operated to support Powerex trade exports (gas purchased by Powerex) under opportune market conditions. It is also operated as part of routine testing.**

**A summary of how IG has been dispatched and the generation that has been purchased is provided in the table below.**

**Table 1 IG Generation (January 2014 through September 2017)**

| **Reason for Operating** | **Energy (MWh)** |
|---|---|
| Vancouver Island Reliability | 70,444 |
| Overall system need | 84,198 |
| Testing | 12,104 |
| Trade | 92,710 |
| | 259,456 |

**71.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-35**

2.71.0 The Panel requests that BC Hydro comment on the viability of pumped storage. BC Hydro is also requested to provide particulars, including but not limited to location, capital and operating costs and general project description of the pumped storage facilities identified as Pumped_Storage_LM in the results of its portfolio analysis.

BC Hydro is requested to respond to the submissions made by Hydro Battery, Clean Balance Power and Van-Port Sterilizers. Specifically, could these projects be lower cost to ratepayers than the pumped storage facilities assumed by BC Hydro, and if yes, what would the cost be (capital cost, O&M etc.) as well as levelized $/kW-year cost (assuming BC Hydro financing costs and a 6 percent discount rate). Please describe any potential non-price related concerns with pumped storage facilities compared to capacity focused DSM/batteries (for example, development time, environmental concerns etc.).

Please describe any additional benefits that pumped storage can provide in addition to be used to firm intermittent resources (for example, as a result of the flexibility of pumped storage), and comment on whether these benefits could reduce the cost of the pumped storage project.

**RESPONSE:**

**<u>Pumped Storage Characteristics</u>**

**There are a few important characteristics to consider in evaluating pumped storage as a resource to meet future system needs.**

- **Pumped storage hydro is a clean source of dependable capacity. It is a mature technology. Over 140 GW of pumped storage facilities have been installed throughout the world. There is one facility in Canada: the Sir Adam Beck Pump Generating Station facility in Ontario commissioned in the late 1950s.**

- **Pumped storage hydro facilities have the ability to respond quickly to changes in system conditions. Their output can be altered as desired with the proper equipment and controls. It is also possible to switch between generation and pumping modes within a few minutes.**

- **The flexibility of the facilities is influenced greatly by the size, characteristics, and constraints of the two reservoirs. The continuous number of hours that the facility can either generate or pump will be influenced by the reservoir storage limits. Fisheries, recreation, and other considerations will also impact the capabilities and flexibility of the facilities.**

- **Pumped storage facilities are a net consumer of energy. Only around 70 per cent of the energy consumed during the pumping cycle can be recovered during the generation cycle. This means that a portion of system energy needs to be dedicated to facilitate the operation of a pumped storage facility. This requirement is significant. For example, a 1000 MW pumped storage facility that operates at around 18 per cent capacity factor to meet the winter peak needs of the BC Hydro system will require 600 GWh/year of firm energy to compensate for energy losses.**

**<u>Pumped storage option used in the modelling</u>**

**BC Hydro has commissioned studies by Knight Piésold Ltd. to identify greenfield pumped storage potential in the Lower Mainland, Vancouver Island and North Coast regions. BC Hydro used the lowest cost facility identified in the consultant studies to characterize the pumped storage facilities identified as 'Pumped_Storage_LM' in the results of its portfolio analysis.**

**The site is identified as 'Upper Deserted – Un-named' in the Knight Piesold report[1] and has an installed capacity of 1,000 MW, a capital cost of $ 1.32 billion ($1,320/kW) and fixed annual operating cost of $12.6 million. The project is located in the Lower Mainland region and provides transmission benefits to the portfolios by deferring or avoiding transmission upgrades from the interior to the lower mainland. BC Hydro also notes that the sites identified and facilities estimated in the Knight Piesold study would have storage sufficient for only six hours of continuous generation. This is insufficient to meet BC Hydro's peak winter demands that requires 16 hours of continuous generation. A facility that can provide 16 hours of generation would require a larger upper reservoir and have higher capital cost.**

**For the portfolio modelling, BC Hydro has assumed that the pumped storage cost estimate was sufficient to provide a ten-hour pumping cycle such that each facility would pump for 14 hours and generate for ten hours. This assumption combined with the use of the lowest cost pumped storage option studied to represent all pumped storage potential provides a favorable low cost assessment in the modelling that BC Hydro has carried out. BC Hydro also notes that the cost of the modelled facility ($1,320/kW) is significantly lower than the range identified by**

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[1] **Report can be found at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a30-nov-2013-irp-appx-3a-30.pdf.**

**Deloitte ($1,600 to 7,300/kW). Deloitte expects O&M costs to be 1 to 2 per cent of capital cost. BC Hydro's assumption matches the lower end of this range.**

**Other submissions**

**BC Hydro has also looked at the submissions made by Hydro Battery, Clean Balance Power and Van Port Sterilizers. The submissions provide conceptual information on three project proposals. BC Hydro does not believe that these projects will provide lower costs to ratepayers than the pumped storage facilities assumed by BC Hydro for the reasons given below.**

- **The cost of the Hydro Battery project is $ 2,180/kW and is significantly higher than the value used by BC Hydro in its modelling.**

- **The Clean Balance project does not seem to include permitting costs nor the cost of transmission to interconnect to the 500 kV transmission system and any access roads that maybe required. The value used in BC Hydro's modelling includes all of these costs which are a necessary part of project development. Permitting costs were estimated to be 6 per cent of the project capital cost in the Knight Piesold studies while transmission costs for the 'Upper Deserted – Un-named' project used in the modelling was around 7 per cent of the project capital cost. BC Hydro estimates that once these costs (13 per cent in total) are incorporated the Clean Balance proposal cost would be extremely close to the value used in the modelling.**

- **The Van Port Sterilizers submission does not provide any cost information. The submission refers to a project proposal that was examined in BC Hydro's 2008 Long Term Acquisitions Plan (LTAP) filing. The proposal described in the 2008 LTAP Appendix F4 involved utilizing treated sewage as the fluid medium and a coal fired power plant to supply energy for the pumped storage facility. This proposal was deemed to be non-viable at that time due to reasons including the fact that provincial legislation requires coal fired facilities to fully sequester their emissions. BC Hydro has no additional information to revise that conclusion.**

**Non-price related concerns**

**The permitting process for a type of generating facility that has not been built since the 1950s will be uncertain. This uncertainty could impact facility development time which BC Hydro expects to be around eight to ten years. Environmental considerations specific to pumped storage include issues related to mixing of water between two reservoirs. This could be mitigated by the use of an artificial reservoir and through closed loop systems where the water used by the facility is in a hydraulically closed loop.**

**The other major area that BC Hydro continues to investigate is how to integrate a ten hour resource into the system when 16 hours is needed in the winter peak**

**period and how to accommodate the pumping requirement that is needed to refill the reservoir in the off-peak periods.**

**<u>Additional benefits</u>**

**The dependable capacity contribution and transmission deferral benefits of pumped storage are explicitly captured in the portfolio modelling. Pumped storage can also provide many of the dispatchable capacity benefits identified as being applicable to Site C in Appendix F of BC Hydro's August 30 Filing. The extent to which a pumped storage facility can provide the benefits will be subject to the flexibility constraints identified above. The dispatchable capacity benefits of Site C have not been monetized and are not reflected in the in the unit energy cost and present value benefit calculations and pumped storage has been treated in exactly the same manner in BC Hydro's analysis. BC Hydro expects such benefits to be smaller for pumped storage than Site C given the limited storage capability of typical pumped storage facilities.**

**Other alternative capacity resources include battery storage and Capacity Focused DSM. Battery storage options would operate very similarly to a pumped storage facility with about 10 per cent cycle energy losses and the need to supply power for at least 10 hours and then they would require a recharge cycle. To date and for the foreseeable future, battery capacity is expected to be a much higher cost than for pumped storage of similar storage capability. The main comparison with Capacity Focused DSM is that it may require customers to respond, individual customer responses may be much shorter but can be combined and customers may similarly require a recovery period after a curtailment that will result in higher usage rates.**

**77.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 87**

2.77.0 BC Hydro is requested to comment on whether it is appropriate to add an adjustment to the UEC to account for sales of surplus energy and capacity. Should Site C costs be reduced by the value of surplus energy sold on the market, with a corresponding reduction in energy volumes?

**RESPONSE:**

**The value of system surplus is more appropriately accounted for in a portfolio PV calculation (or a UEC derived from the portfolio PV analysis) than in the unit energy cost of specific resources, such as Site C, or in the Block UEC analysis for the two key reasons outlined below. For a description of our alternative portfolio UEC metric please refer to BC Hydro's response to BCUC IR 2.45.0.**

1. **Resources are generally acquired to meet system need so any system surplus created (by Site C or other resources) is generally expected to persist for a relatively small portion of their project life.**

2. **Surplus energy occurs at different times of the year and may not be directly attributable to a specific resource such as Site C;**

**Further, adjusting the UEC for reduced energy volumes to reflect surplus sales would not align with the Panel definition of Unit Energy Cost because it would no longer reflect the "cost per unit of <u>energy produced</u>".**